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RIIO T1

Strategy for the next transmission price control - RIIO-T1 Outputs and incentives

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Target Audience: Consumers and their representatives, transmission companies, generators, offshore gas producers/importers, suppliers, shippers, investors, environmental organisations, distribution network companies, government policy makers and other interested parties.

Overview:

This is the first transmission price control to reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model. RIIO is designed to drive real benefits for consumers; providing network companies with strong incentives to step up and meet the challenges of delivering a low carbon, sustainable energy sector at a lower cost than would have been the case under our previous approach. RIIO puts sustainability alongside consumers at the heart of what network companies do. It also provides a transparent and predictable framework, with appropriate rewards to promote timely investment in the networks.

Having consulted on our initial strategy for the next transmission price control, this supplementary annex to the main decision document sets out in more detail our decision on the outputs that the network companies will need to deliver over the price control period, and the associated incentive mechanisms. This document is aimed at those seeking a detailed understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the main decision document.

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Associated Documents

Main decision paper

- Decision on strategy for the next transmission price control - RIIO-T1
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Links to supplementary annexes

- Decision on strategy for the next transmission price control - RIIO-T1 Tools for cost assessment
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisioncosts.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Business plans, innovation and efficiency incentives
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionbusplan.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Financial issues
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionfinance.pdf
- Decision on strategy for the next transmission and gas distribution price controls - RIIO-T1 and GD1 Uncertainty mechanisms
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisionuncert.pdf

Links to other associated documents

- Providing a greater role for third parties in electricity transmission: Early thinking and options
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/thirdpartyrole.pdf
- Consultation on strategy for the next transmission price control - RIIO-T1 Overview paper (159/10)
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1%20overview.pdf
- Handbook for implementing the RIIO model - Ofgem, October 2010
  http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf
- A glossary of terms for all the RIIO-T1 and GD1 documents is on our website:
  http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decisiongloss.pdf

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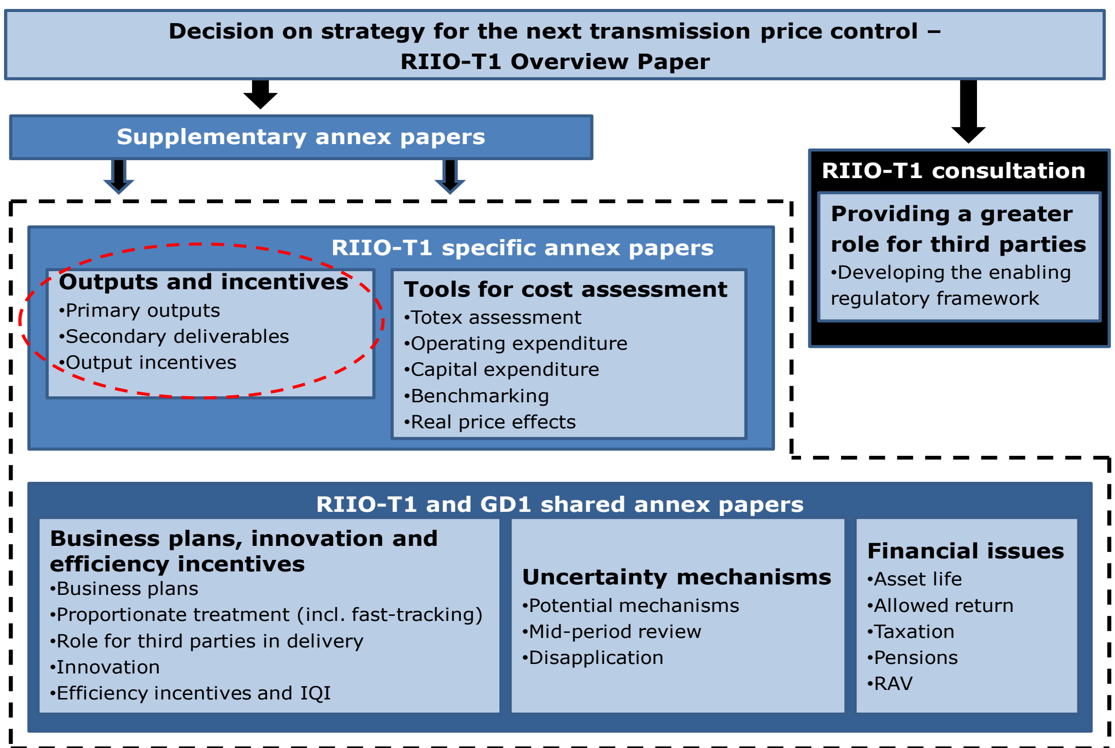
1. Introduction

1.1. The next transmission and gas distribution price controls, RIIO-T1 and GD1, will be the first to reflect the new RIIO model. These price controls will be set for an eight-year period from 1 April 2013 to 31 March 2021. In December 2010, we consulted on our initial strategy for the RIIO-T1 price control review.[1] This included a supplementary annex covering proposals for the outputs that the transmission owners (TOs) will need to deliver over the price control period.

1.2. Having considered responses to the initial strategy consultation, this document sets out our decision on the outputs, and the associated incentives. The purpose of this document is to explain to companies the arrangements in more detail so they can submit well-justified business plans in July 2011. Stakeholders wanting a more accessible overview should refer to the RIIO-T1 overview paper.[2] Figure 1.1 shows the suite of RIIO-T1 decision documents. We have also published a consultation on providing a greater role for third parties in electricity transmission.

Figure 1.1: RIIO-T1 Supplementary appendix document map*



***Document links can be found in the 'Associated documents' section of this paper.**

[1] Consultation on strategy for the next transmission price control - RIIO-T1 Overview paper, Ref 159/10 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIOT1%20overview.pdf

[2] Decision on strategy for the next transmission price control - RIIO-T1 Overview paper, Ref 46/11 http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/T1decision.pdf

Key decisions on RIIO-T1 outputs and incentives

1.3. Our strategy decisions on the outputs and associated incentives have taken into account stakeholders' views on the proposals in the December document. We have considered both written responses as well as feedback given in working groups, stakeholder forums and bilateral discussions. We are grateful to those that have taken the time to make contributions to this process.

1.4. Table 1.1 summarises our decisions in relation to the proposals outlined in our December document.

Table 1.1: Key decision areas

Outputs or policy area	December proposal	Our decision/way forward
(1) System Operator (SO)/TO interactions	Consider options for aligning SO and TO incentives.	Arrangements for SO and TOs to work together in managing short-term constraints and gas shrinkage and venting. We will develop further in longer-term SO incentives work.
(2) Broad environmental output	Consider a broad environmental output and the type of incentive to apply.	We intend to introduce a broad environmental output with a reputational incentive. We will consult further on a financial incentive for electricity trans.
(3) Visual amenity	Guidance on considering the socio-environmental impacts of infrastructure in business plans.	Alongside guidance, we intend to introduce an allowance to reduce the visual impact of existing infrastructure in designated areas.
(4) Electricity transmission losses	Consider a financial incentive for losses.	We intend to set a reputational incentive on modelled avoided network losses.
(5) Customer satisfaction	Incentive on customer satisfaction based on +/-0.5% of allowed base revenue.	We intend to increase the incentive strength to +/-1% of allowed base revenue.
(6) Reliability - electricity	Reliability output using energy not supplied (ENS) and no collar on exposure.	We intend to introduce a 3% of revenue collar on financial penalties and a licence condition for minimum standard of performance.
(7) Wider works secondary deliverable	Arrangements for electricity TOs to deliver timely and efficient investments.	Secondary deliverables for wider reinforcement works. Three flexibility mechanisms to adjust base revenue and financial incentives for timely delivery.
(8) Efficiency incentive rate	Consider the efficiency rate for TOs.	We intend to apply a 40-50% efficiency incentive rate.

1.5. We have sought to ensure that the rewards/penalties associated with incentive mechanisms reflect the value that consumers place on the output, and that incentivised output measures fulfil the requisite criteria (ie controllable, material etc.) to ensure companies and consumers do not face windfall gains or losses.

1.6. In addition we want network companies to face strong financial incentives to control their costs and implement delivery approaches that provide better value for money for existing and future consumers. The RIIO model proposed a fixed and symmetric efficiency incentive rate for each company to give companies a strong financial stake in restraining, and where possible reducing, the costs of delivering outputs over the price control period. The exact efficiency incentive rate for each company will be set as part of the Information Quality Incentive (IQI) in RIIO-T1.

1.7. Where an incentive associated with a particular output is related to the economic value of a unit change in the output we will apply the efficiency incentive. This means that for outputs with an incentive related to an economic value per unit of output such as, Energy Not Supplied and the value of lost load (VOLL), and sulphur hexafluoride emissions (SF_6) and the non-traded carbon price, we will adjust the reward/penalty that a TO faces by the efficiency incentive rate.

1.8. This adjustment is required to ensure that the companies make expenditure trade-offs that are in the consumers' best interests. For example, if this adjustment was not made, then companies have an incentive to over invest as they receive a reward based on the economic value of the output but can pass through the costs of any investment to customers (say 50 per cent) under the efficiency incentive rate.

Structure of document

1.9. The remainder of this document sets out our decision on the output framework and the specific outputs and incentive mechanisms for each output category.

- Chapter 2: Outputs framework
- Chapter 3: Safety
- Chapter 4: Environmental impacts
- Chapter 5: Customer satisfaction
- Chapter 6: Reliability - electricity transmission
- Chapter 7: Secondary deliverables for wider works in electricity transmission
- Chapter 8: Reliability - gas transmission
- Chapter 9: Conditions for connection

2. Outputs framework

Chapter Summary
This chapter sets out our strategy decision on the outputs framework, reporting requirements and the changes to the outputs we have made since December.

2.1. In our December document, we asked for respondents' views on our approach to the development of the outputs and incentives package; whether we should introduce additional reporting requirements on companies to enable us to monitor and evaluate their performance against the outputs package; and our proposed approach to modifying output measures within the price review period.

2.2. In this Chapter, we briefly summarise our December proposals, stakeholder views, and our decisions with regard to these issues. As set out below, we will continue to refine the reporting requirements for the output measures in our output working groups. An important aspect of our further work will be to ensure that the reporting requirements are proportionate. We also confirm our position to revisit outputs only within the scope of the limited mid-period review, or where there is measurement error or the measure is unfit for its intended purpose.

Summary of consultation proposals

Development of outputs framework

2.3. A core component of the RIIO framework is the development of an outputs-based regulatory framework. An outputs-based approach provides powerful incentives for companies to innovate and seek least cost ways to provide network services. The approach also gives stakeholders a greater opportunity to determine what outputs network companies should deliver, and greater transparency of companies' performance in delivering these outputs over the price control period.

2.4. In addition to the suite of primary outputs, we also proposed to set "secondary deliverables" for TOs on asset health and wider works in electricity transmission over RIIO-T1. These are essential elements of the package to ensure delivery of primary outputs in both the next and future price control periods.

Reporting requirements

2.5. As set out in our December document, we will need to introduce new reporting requirements on companies to enable us to monitor and evaluate companies' performance against the set of output measures and revenue adjustment measures.

2.6. We have two main reporting processes to enable us to monitor licensees' performance for the current price control. We require licensees to submit to us on an annual basis regulatory reporting packs (RRPs) which provide a common framework for the collection and provision of accurate cost information. We also require TOs to submit data as set out in our Regulatory Instructions and Guidance (RIGs), which provides a common framework for TOs to report relevant outputs, standards of performance and revenue data to us, and for us to monitor their performance.

2.7. In our December document, we proposed to finalise the RIGs by the end of December 2011, in advance of agreeing price controls with any company that is fast-tracked.

2.8. We also invited respondents' views on whether any of the proposed output measures would present companies with difficulties in terms of submitting accurate and comparable data.

2.9. We asked whether we should require companies to provide us with an additional assurance as to their accuracy of the data submissions, eg appointing an independent reporter.

Changes to outputs

2.10. In December, we proposed a mid-period review of outputs which would allow for changes to the agreed measures only where these were justified by changes in government policy or legislation. We also proposed to allow the introduction of new outputs where these were required to meet the needs of consumers and other network users.

2.11. We acknowledged that we might need to make changes where we identify an error in setting the target/baseline output level or the associated incentive rate; and, where the proposed reporting or measurement of an output is unfit for its intended purpose (eg where we identify scope for gaming on reporting of the figures).

Summary of responses

Development of outputs framework

2.12. Most respondents supported our approach to the development of the outputs framework. In particular, respondents welcomed the development of the output measures through the use of the working groups, comprising both network companies and wider stakeholder groups.

2.13. A number of the respondents noted that the timetable for the development of the outputs and incentives had been relatively tight, and that we would need to continue to develop the outputs package post March in conjunction with the industry. TOs also noted that they need more detail on the outputs and the associated incentive mechanisms.

Reporting requirements

2.14. One respondent set out the view that there could be possible difficulties reporting data, particularly for areas or outputs that are not readily observable and will need some modelling. They also noted that it will be necessary to have consistent methodologies for companies. Another respondent said that they could not fully respond to this question until the output measures were further refined.

2.15. On the question of whether it would be appropriate to require companies to appoint an independent reporter, one respondent said that it would be important that the reporter had sufficient experience to assess companies returns correctly. Another said that the benefits would have to justify the costs.

Changes to outputs

2.16. Most respondents agreed to our approach to limiting the scope for adjusting outputs at the mid-period review to changes required by legislation or government policy, and to new output measures.

2.17. One TO thought there might be good cause to include the provision to change an output if incentives were calibrated incorrectly and led to high and undeserved penalties.

Our decision

Development of outputs framework

2.18. The RIIO process identified six key output categories, or key areas of delivery, for network companies. The output categories are: safety; environmental impact; customer satisfaction; reliability; conditions for connection; and social obligations.

2.19. With the exception of social obligations, we are setting outputs in each of these areas. We do not intend to place any social obligations on the TOs. This was because there are not currently any specific social obligations on the companies in transmission and we do not see any rationale for introducing new obligations.

2.20. We will continue to work with the industry and other stakeholders in the coming months on the outputs framework and regulatory reporting. In most cases, where we have set out detailed definitions and incentive mechanisms, the focus will be on finalising the reporting requirements. In general, we do not expect companies to propose new outputs and incentive mechanisms for issues generic to the industry, and which have been considered in-depth and resolved in the working groups and other stakeholder forums.

2.21. There are one or two areas in RIIO-T1 that require further work on the definition of the output and the incentive mechanism. For example, as set out in Chapter 4, we need to finalise the output measure and incentive structure for a broad environmental output once we have received companies' business plans in July. Nonetheless, this decision document gives a sufficient steer on the direction of travel for TOs to fully incorporate in their well-justified business plans.

2.22. Companies will also have some scope to propose additional or alternative outputs and incentive arrangements providing they justify that these address the specific needs of their stakeholders, ie as evidenced from their stakeholder engagement process. We expect companies' own stakeholder engagement to inform their business plans in a number of important areas including their baseline projections.

Reporting requirements

2.23. As set out in December, we will work with the industry to develop and finalise the data reporting arrangements that will accompany the price control settlement. We envisage having proposals on the RIGs and the compliance arrangements discussed below for inclusion in the December fast-track consultation document. Throughout this process we will look to ensure that the reporting requirements, and the arrangements that are in place to check the accuracy of this information are both effective and proportionate.

2.24. We have already started to review the arrangements we have in place to ensure the accuracy of data submitted by licensees. The reporting requirements on the GDNs, DNOs and TOs and the associated assurance requirements have developed over time and we employ a variety of methods to provide assurance that data submitted is accurate. While the existing arrangements in this area have been largely effective in providing comfort on the reliability of regulatory returns, there is scope to introduce a more coherent assurance framework, where greater assurance is required for the areas of highest risk.

2.25. The transition to an outputs focused regime and the new areas of reporting that this will entail make this an appropriate time to carry out such a review. The decision that follows the completion of this work may involve us introducing additional assurance requirements (discussed briefly below), which would require the licensees to incur additional costs in this area. If the conclusions arising from this work do have significant cost implications, licensees will have the opportunity to update their business plans to reflect this.

2.26. We are looking to introduce an approach where the measures to ensure data accuracy are proportionate to the potential impact misreporting of any particular data category could have on customers (in terms of the outputs they receive or the price they pay for network services) and reflect the incentive companies have to misreport.

2.27. We are considering whether the principle of proportionality should extend beyond the inherent risk associated with individual data submissions and should also take into account an assessment of the internal systems and processes of each licensee. This assessment could include, for example, companies’ governance frameworks, the robustness of their systems, past performance in providing accurate data and the introduction of new systems and processes. Under this type of arrangement, certain assurance requirements would apply to all companies, with more stringent requirements applying only to those licensees where there is deemed to be a higher risk of misreporting.

2.28. This review considers, as one option, the benefits of introducing requirements for companies to appoint independent reporters. At this stage, we do not anticipate making a recommendation on the introduction of the type of scheme employed in the water and sewerage sectors, whereby each company appoints an individual with a joint duty of care to the company and regulator to examine the systems used in preparing the principal annual reporting submissions and to review the company's performance. However, we could see merit in similar but more focussed arrangements with the reporter looking solely at the robustness of regulatory reporting.

2.29. We can also see potential benefits in a system where a reporter would examine a particular category of data reporting across all of the licensees within a sector (for example, network reliability output reporting). This would be particularly relevant where data is used for carrying out comparisons between companies, such as the benchmarking of particular areas of expenditure or in gaining assurance that technical output information is reported accurately, and would enable us to focus on specific aspects of company reporting, for example, where we have introduced a new reporting requirement. Areas under review would change over time, in response to changing priorities or concerns.

2.30. Under the current arrangements, we require certain regulatory submissions, such as the cost and revenue reporting packs, to be accompanied by 'director sign-off' sheets. Other options under consideration are whether to sharpen these arrangements by being more specific on the level of sign-off required and by defining more precisely what we expect such a sign-off to represent and whether to extend these arrangements to a wider range of submissions.

2.31. We will do further work on the development of the criteria that could be used in assessing the risk associated with individual companies and on how these assessments will be used to determine the types of assurance activity to be carried out. In particular, we will be looking to get a better understanding of the licensees' systems and processes covering the submission of regulatory data, which would form a significant part of such an assessment. We will also work with the licensees to get a more comprehensive view of the risks associated with different categories of reporting. To this end, we will look to form industry working groups to discuss these issues further. As is currently the case, we expect the compliance requirements to appear across the relevant licence conditions and RIGs documents.

Changes to outputs

2.32. We confirm our proposal to have a limited scope mid-period review of outputs. We set out our decision in more detail in Chapter 7 of 'Supplementary Annex - Uncertainty mechanisms'. We also confirm our proposal to revise outputs measures outside of this process only where we identify an error, or the measurement/reporting of an output does not meet the intended purpose.

3. Safety outputs and incentives

Chapter Summary
This chapter sets out our strategy decision on safety outputs, associated secondary deliverables and incentives.

3.1. TOs are required by legislation to design and operate their networks to ensure the safety of the public and employees. The Health and Safety Executive (HSE) monitors and enforces performance in this area.

3.2. Our strategy decision is that the primary output for safety for gas and electricity transmission is for the TOs to comply with their legal safety requirements. This mirrors the obligations with the HSE and therefore reflects the existing safety regime. We will monitor the long-term delivery of this primary output through secondary deliverables relating to asset risk (asset health, criticality and risk). We will not attach financial incentives to the primary safety outputs as other agencies and mechanisms (the HSE and legal obligations) incentivise the companies to deliver in this area.

3.3. The primary outputs, secondary deliverables and associated incentives for safety are unchanged from our initial proposals as respondents generally supported our views.

3.4. The following section provides a background and context to setting safety outputs. We then present a summary of our consultation proposals and the responses we received from stakeholders. Finally we present our strategy decision on safety outputs and the reasons for this.

Background and context to setting safety outputs

3.5. The TOs are subject to a range of legal safety obligations. In the case of electricity transmission, this includes:

- The Electricity Safety Quality and Continuity Regulations 2002 (ESQCR) that specify the standards that TOs (and their contractors) must adhere to on their networks. It also specifies events which must be reported to the Secretary of State (for example deaths and injuries occurring to members of the public caused by the network).
- The Health and Safety at Work etc. Act 1974 (HSWA), which makes provision for securing the health, safety and welfare of persons at work and for protecting others against risks to health or safety in connection with the activities of persons at work.[3]
- The Electricity at Work Regulations 1989 (EAWR), which also ensure health, safety and welfare of persons at work specifically in relation to electricity.

[3] See 'Introductory text' of the 'Health and Safety at Work Etc. Act 1974'.

3.6. The HSE oversees TO compliance with these requirements. In the event of non-compliance, the HSE has a number of sanctions available to them to secure compliance with the law and to ensure a proportionate response to criminal offences. Inspectors may offer duty holders information and advice, both face to face and in writing. This may include warning a duty holder that, in the opinion of the inspector, they are failing to comply with the law. Where appropriate, the HSE may also serve improvement and prohibition notices, withdraw approvals, vary licence conditions or exemptions, issue simple cautions (England and Wales only), and they may prosecute (or report to the Procurator Fiscal with a view to prosecution in Scotland).[4]

3.7. In the case of gas transmission, NG Gas plc (NGG) must comply with:

- The Gas Safety (Management) Regulations 1996 (GS(M)R) which stipulate that the TO must produce a safety case which describes how they will manage the gas network and how they will deal with emergencies. This safety case is subject to acceptance and routine inspection by the HSE.[5]
- The HSWA as set out above.
- NGG must also provide the HSE, the Scottish Environment Protection Agency (SEPA) and the Environment Agency (EA) with a risk assessment in accordance with the GS(M)R, the Control of Major Accident Hazard Regulations 1999 (COMAH), and the Pipeline Safety Regulations 1996 (PSR).[6]

Summary of consultation proposals

3.8. The proposal we set out for consultation in December was that:

- The primary output for safety should be for the TOs to comply with their legal safety requirements. We would ensure the long-term delivery of this primary output through secondary deliverables relating to asset risk (asset health, criticality and replacement priorities/risk).
- We would not attach financial incentives to the primary safety outputs as other agencies and mechanisms (the HSE and legal obligations) incentivise the companies to deliver.

Summary of responses

3.9. Respondents generally supported our consultation proposals for safety outputs during RIIO-T1 with one respondent noting that the outputs should support rather than duplicate the functions of the HSE. Another noted that the secondary deliverables would provide assurance that companies are providing stewardship of their network through management of asset condition and the risk this presents to stakeholders. One respondent noted that it does not believe that further reporting to Ofgem is necessary.

[4] HSE, 'Enforcement Policy Statement', http://www.hse.gov.uk/pubns/hse41.pdf
[5] Further detail provided in the Gas Safety (Management) Regulations 1996 'Safety Case Assessment Manual' http://www.hse.gov.uk/gas/supply/gasscham/gsmrscham.pdf
[6] Frontier Economics, RPI-X@20: Output measures in the future regulatory framework, http://www.ofgem.gov.uk/Networks/rpix20/ConsultReports/Documents1/rpt-outputs.pdf

3.10. The HSE generally agreed with our proposed safety outputs in electricity and gas transmission. It noted that the legislative framework for electrical safety does not require the TOs to report on a set of metrics for measuring compliance against legal safety obligations and recommended considering a broader set of metrics. It recognised our intention to support rather than duplicate HSE's functions and noted that it will further consider what advice it can provide the TOs in developing the safety elements of their business plans. One respondent also noted that TOs could consider developing other areas under the definition of leading secondary deliverables as part of their well-justified business plan.

3.11. Two respondents questioned whether it was appropriate to include safety as part of the RIIO regulatory incentives arguing that because of its importance it is already subject to statutory requirements and penalties.

Our decision

Primary outputs and secondary deliverables

3.12. Our strategy decision is that the appropriate output for safety is compliance with the safety requirements which are set out in legislation and monitored by the HSE. This output is measurable (a TO is either legally compliant or it is not) and comparable (all TOs must abide by the same legislation).

3.13. We consider it important to include a safety output for RIIO-T1 even though the TOs are subject to existing statutory requirements. Our outputs support rather than duplicate these requirements. Network companies will be expected to include in their business plans costs associated with delivery of safety obligations set by the HSE, and consider safety when assessing how best to manage overall network risk. Therefore, it is important that when undertaking price control reviews we understand what is being delivered in terms of safety and how it links to costs.

3.14. We note the HSE's comments that, in the case of electricity transmission, legislation does not require the TOs to report on a set of metrics for measuring compliance but rather requires them to assess safety risks within their operations and take proportionate risk-based measures to address them. We consider the HSE and Government are best placed to decide on the approach that should be taken to regulating safety in the electricity transmission sector. It is our view that our primary output should support, rather than duplicate, their functions.

3.15. The HSE has advised that there are areas that it considers important for TOs to address in developing their well justified business plans and will work with the TOs to articulate these further. We consider this an important part of the TOs developing their plans and demonstrating compliance with the primary output but maintain our view that they should not necessarily be included as secondary deliverables in our outputs framework.

3.16. As is the case for all of our output categories, the TOs may propose additional secondary deliverables in their business plans. To include them in the price control settlement and fund their delivery, we would need to be satisfied that any additional secondary deliverables are not already captured by other outputs and we will use the drivers identified in the RIIO handbook when assessing them.[7]

3.17. We envisage that strong bilateral engagement between ourselves and the HSE, will be ongoing over the price control period so that:

- the HSE can continue to assist Ofgem to understand the safety obligations that the businesses have
- Ofgem can assist the HSE in quantifying the efficient cost of its current and proposed safety requirements
- the HSE can consider new safety proposals set out in the TO business plans.

3.18. It is also our view that the primary output should not stipulate an exhaustive list of legislative requirements but include examples of legal obligations such as ESQCR, HSWA and the GS(M)R. This will ensure that the primary output remains relevant should any further legislative requirements be imposed on the businesses during the price control period.

3.19. Our strategy decision is that the secondary deliverables for both electricity and gas transmission safety should be the asset health, criticality and risk. These secondary deliverables will ensure that delivery of the primary output in future periods is not put at risk by decisions made in the RIIO-T1 price control period. These secondary deliverables are the same as those developed for reliability and provide a framework for managing network risks including safety implications. A description of this framework is contained in Chapters 6 and 8.

3.20. Asset condition (measured through an asset health index) and criticality are currently reported under Standard Licence Condition B17 Network Output Measures (NOMs) of the electricity transmission licence and Special Condition C13: Network Output Measures of the gas transporter licence. We have decided that these measures need further development as part of this price control review and have set out further details of our changes in Appendix 2.

Incentives

3.21. As noted above, our strategy decision is not to attach financial incentives to the primary safety output as the TOs are incentivised by other agencies and mechanisms. This decision is consistent with our consultation proposal that was supported by respondents.

[7] These drivers include managing network risk to ensure that delivery of primary outputs in future periods is not put at risk by decisions made in the price control period; projects for delivering primary outputs in future periods with action taken during the price control period; and technical and commercial innovation projects or other projects which require upfront costs but have the potential, with some uncertainty, to deliver benefits in terms of long-term value for money in future periods.

3.22. Our view is that it is not appropriate for us to apply further specific penalties on the primary output. In deciding on a penalty to impose on any business, the relevant agency (be that the HSE or a Court) will take into account several factors including the impact on the public as well as the degree to which the penalty should act as a disincentive for future poor performance. A court would have regard to the degree of reputational damage suffered by the business. We are also concerned that, in cases where a penalty has not yet been imposed on the business (for example in the case of criminal sanctions), it could also place Ofgem in a position of pre-empting the decision of the relevant agency.

3.23. We note that our customer satisfaction outputs, which look at survey evidence, complaints handling and stakeholder engagement, will include elements of the reputational damage that TOs may suffer due to poor performance in several areas including safety. Further detail of this measure is provided in Chapter 5.

3.24. We will apply an incentive framework for secondary deliverables that will require the TOs to demonstrate how their expenditure is linked to managing network risk both at the beginning and end of the price control period. This is described in Chapter 6.

3.25. In summary, we will assess whether the TO has performed satisfactorily and delivered the reduction in asset health related network risk it agreed to deliver over the course of RIIO-T1 and carry forward the agreed baseline secondary deliverables to the next control period. Network companies should be able to recover their share of the over spend (under the IQI incentives) relating to over delivery if they can demonstrate this is positively valued by customers, and that the costs incurred were efficient. Similarly, we would look to recover the under spend if the TOs are not able to demonstrate this. We consider that this approach is consistent with the RIIO recommendations and the longer-term approach to price controls.

3.26. TOs will also be required to provide ratings of the asset health, criticality and replacement priorities at annual intervals throughout the price control.

4. Environmental impacts

Chapter Summary
This chapter sets out our decisions on the outputs to address the environmental impacts of transmission networks. We summarise stakeholders' responses to our December proposals and our consideration of the issues raised. We also provide more information on the specific environmental outputs and associated incentives and our reasons for adopting these in the RIIO-T1 price control strategy.

4.1. One of the overriding objectives of the RIIO regulatory framework is to ensure network companies play a full role in delivery of a sustainable energy sector. This includes taking responsibility for the direct impacts of their networks on the environment as well as playing their full role in a low carbon economy.

4.2. In RIIO-T1, the first price control to implement the new RIIO framework, we are alive to the opportunity to drive a step change in transmission companies' contribution to the UK's low carbon goals. The complete RIIO package provides powerful incentives to encourage network companies to meet the environmental challenges. This includes:

- the requirement to develop a well-justified business plan
- specific environmental outputs, including a broad environmental output
- the wider output framework, with a number of outputs (such as connection standards) also supporting environmental objectives
- a time limited innovation stimulus which allows companies to make the ongoing adjustments to their operations to meet changes in consumers' needs.

4.3. In the December document we consulted on a set of specific environmental outputs to cover the impacts of transmission networks across the following areas:

- broad environmental impacts
- direct network emissions
- wider environmental footprint.

4.4. The table below summarises the combination of outputs and other mechanisms within RIIO-T1 to encourage TOs to address the direct impacts of their networks as well as play their full role in a low carbon economy.

Table 4.1: Elements of RIIO package supporting environmental objectives

Behaviours	**Price control mechanism**	**Incentive strength**
TOs play a full role in achieving a low carbon economy.	TOs to set out strategy to contribute in well justified business plan.	If strategy not sufficient TO will not be fast-tracked and will be subject to greater regulatory scrutiny.
	Broad environmental output for low carbon energy flows.	Reputational incentive for gas and electricity trans. We will consult on a financial incentive (elec only) for contribution to low carbon economy.
	Network innovation competition	£400m over RIIO-T1.
	Customer satisfaction survey	+/- 1% of allowed revenue.
TOs look at good value and innovative ways to deliver low carbon objectives and environmental objectives.	Can justify innovative solutions if long term benefits for consumers.	Allowance in base revenue.
	Innovation allowance	0.5% to 1% of base revenue.
	Network innovation competition	£400m over RIIO-T1.
TOs provide good and timely service to network users.	Connections output	0% to -0.5% of base revenues.
	Secondary deliverables and flexibility mechanisms for local enabling works and wider reinforcement work.	Allowance in base revenue or volume drivers.
TOs reduce their direct impacts on environment eg greenhouse gas emissions.	Outputs and measures for networks' direct emissions, eg business carbon footprint, SF_6, transmission losses, gas shrinkage and venting.	Mix of reputational and financial incentives.
TOs reduce their wider environmental footprint.	Company demonstrates in business plan needs case to mitigate impacts of new infrastructure on visual amenity.	Allowance in base revenue.
	Company allowance to mitigate impacts of existing infrastructure in designated landscapes.	To be determined by consumer willingness to pay analysis.
	Network innovation competition	£400m over RIIO-T1/GD1.

Broad environmental output

4.5. The transition to a low carbon economy will bring significant opportunities and challenges for the energy networks. During RIIO-T1 and beyond, electricity transmission companies will invest billions in their networks to accommodate a huge increase in new low carbon generation. Companies will need to manage the uncertainties associated with new technologies and large investments to deliver timely, good value and sustainable network infrastructure.

4.6. The stakeholder working group looking at environmental outputs has discussed how to encourage and reward companies to meet this challenge effectively. One suggestion was to align TO incentives directly with the UK's low carbon energy goals by setting a broad output on TOs' contribution to meeting the UK's renewable energy target.

4.7. A broad environmental output was seen as a way to give companies a vested interest in the achievement of the UK's renewable and low carbon targets. It was also thought an output that was linked to the UK's targets was consistent with RIIO's high-level objective of encouraging network companies to play a full role in delivery of a sustainable energy sector. It was argued that harnessing TOs' efforts on reducing the carbon intensity of generation and energy use on the system could bring more material benefits than reducing the network's carbon footprint.

Summary of consultation proposals

4.8. We consulted in December on the need for a broad output on TOs against their contribution to the low carbon economy. We sought views on what TOs full role in a low carbon economy might include and asked stakeholders to consider the type of incentive that it is appropriate to apply to a broad output.

4.9. We also asked stakeholders to give their views on a strawman proposal developed by RenewableUK for a broad output. In this proposal TOs would have an output set against the UK’s 2020 renewable energy target and/or the rate of decarbonisation of grid electricity recommended by the Committee on Climate Change. RenewableUK's strawman included applying an upside only financial reward which could be calculated as a marginal incentive depending on the incremental changes in the output measure. Alternatively, this could be set as an agreed bonus, say a percentage of total revenue for meeting a threshold in the output measure. The strawman also suggested different ways of allocating the financial reward. This could be as a team bonus shared between the different companies, as an individual company bonus, or as a combination of a team and individual bonuses.

Summary of responses

4.10. Seven stakeholders representing transmission companies, trade associations, network users, and consumer groups responded to the questions on a broad environmental output. Most of these see some merit in an output on TOs' contribution to a sustainable energy sector. Most thought a broad output based on a high-level measure such as proposed by RenewableUK would fit well in the RIIO output performance model and give flexibility for companies to contribute in new ways over the price control. A couple of stakeholders added the proviso that a high-level output should be technology neutral. One wanted to know more about how such an output would work in practice.

4.11. Some stakeholders qualified their support and had some concerns about setting an output using a high-level measure such as percentage of renewable energy connected. These are: (1) that TOs only have partial control on such a high-level measure and there are other factors, outside of TOs' control, that could significantly influence the volume and siting of new renewable generation, and (2) that a high-level measure would overlap with other RIIO-T1 outputs on TOs for wider reinforcement works, customer satisfaction and connections.

4.12. Stakeholders thought it would be important that any broad measure address these issues, particularly if a financial incentive was applied. Otherwise a broad output using a high-level measure might result in:

- Windfall gains and losses to TOs if outside factors have a greater impact on the output measure than the contribution of the TOs.
- Consumers paying twice for the same output if a TOs contribution is already incentivised under another primary output.

4.13. One TO and large network user thought further clarification was needed on what a broad output would achieve, or alternatively what is currently lacking that it will address.

4.14. Stakeholders also had mixed views about the type of incentive that should apply to a broad environmental output. A consumer group said that a reputational incentive is more appropriate owing to the difficulty in attributing a TO’s activity for a given change in the high-level measure. Conversely, low carbon trade associations and some environmental groups did not think that a reputational incentive would provide enough incentive to a monopoly service provider. Instead they argued that double counting could be avoided if the primary outputs that overlapped with a broad measure were replaced with the most material output for the UK’s energy and environmental targets.

Our decision

4.15. There are strong reputational incentives associated with a network specific broad environmental measure, given the importance placed on these developments by stakeholders, including network users, and Government. We are including a reputational incentive for both the gas and electricity transmission sectors on low carbon developments on their networks.

4.16. Subject to consultation, we intend to introduce an incentivised broad environmental measure for electricity transmission that would:

- embed RIIO's overarching sustainability objective in the output framework
- provide a direct link to progress against the low carbon objectives
- future proof the output framework for new opportunities arising over RIIO-T1.

4.17. Reflecting their significantly greater scope to contribute to the UK's renewable energy targets, we will consult on the potential to introduce a financial reward for the electricity transmission companies on the following basis:

- an automatic incentive potentially linked to a measure of the carbon intensity of energy flows as well as the annual increase in low carbon energy flows
- a discretionary reward if companies can demonstrate they have made a contribution that is in addition to those already rewarded under either the automatic incentive or the wider outputs framework.

4.18. If such a discretionary reward is introduced following consultation, our present view is that the value of any such award could be related to the benefits for consumers and/or the environment that TOs have delivered.

4.19. Key considerations here include the need for value for money for existing and future consumers and the interactions with: incentives on other primary outputs such as customer satisfaction; innovation funding available under RIIO-T1; and government support schemes for renewable and low carbon generation.

Direct network emissions

4.20. Transmission networks can have adverse impacts on the environment through the release of greenhouse gases when they undertake business activities or operate equipment on the network. These are very small compared to emissions from the generation and consumption of gas and electricity. Nonetheless we think it is important that the companies take responsibility for the direct environmental impacts of networks. We intend to set specific outputs or business planning requirements on TOs to manage and mitigate the direct emissions arising from:

- the business carbon footprint (BCF) of gas and electricity transmission companies
- leakage from high voltage switchgear using sulphur hexafluoride (SF_6) in electricity transmission
- network losses in electricity transmission
- gas shrinkage and venting on the gas transmission system.

Summary of consultation proposals

Business carbon footprint

4.21. We proposed that both electricity and gas transmission companies report annually to Ofgem on the carbon dioxide (CO_2) equivalent emissions of their BCF. Our proposals aim to encourage the transmission companies to consider the direct carbon impact of their operations and be proactive in managing these emissions.

4.22. We proposed to apply a reputational incentive on the BCF output as the transmission companies will take financial responsibility for emissions related to energy use in buildings and operational sites under the Carbon Reduction Commitment Energy Efficiency Scheme (CRC). We proposed that licensees be required to report on their emissions covered by the CRC scheme as well as emissions not covered by the CRC scheme or other outputs under RIIO-T1 such as transport emissions.

Sulphur hexafluoride

4.23. We proposed to change the current incentive for SF_6 emissions introduced in the last transmission price control (TPCR4) to move towards the "polluter pays" principle. We also discussed the option of applying the carbon equivalent price for emissions that deviate from baseline.

Network losses

4.24. We consulted on options for a losses output on TOs. We also recognised this was an area where there could be interactions between the roles of the TO and the SO and alignment issues between TOs and SO incentives on losses.

Gas shrinkage and natural gas venting

4.25. We consulted on introducing outputs on National Gas Grid (NGG) in its TO role for gas shrinkage and natural gas venting on the National Transmission System (NTS). We recognised there are interactions with NGG's role as SO relating to gas shrinkage and venting on the system. We proposed to look further at incentives to encourage NGG to optimise the management of shrinkage and venting across both its roles where this is in consumers' long-term interest.

Summary of responses

4.26. Stakeholders were in broad support of the proposals in relation to BCF and SF_6.

4.27. TOs said that there would be limited benefits from an output on actual volume of losses. They said that they have limited influence on actual losses because of the separate roles of transmission owners and the single system operator established in 2005 by the introduction of the British Energy Trading and Transmission Arrangements (BETTA) and other factors – such as the geographical dispersion of generation. A renewable trade association similarly saw this output as of low environmental materiality and had some concerns that a losses output might give perverse incentives not to connect renewable energy which is likely to be located away from demand.

4.28. Very few stakeholders responded to the consultation question on the relative roles of the TO and SO in relation to gas shrinkage and natural gas venting. One respondent thought it would be possible to disaggregate TO and SO activities that contribute to venting. They thought this would be more difficult to do for gas shrinkage because the counter factual network would be difficult to establish. The respondent also noted that TO investments for shrinkage give long-term benefits and that short-term incentives would underestimate the net benefits of investment. To overcome this problem they suggested that the TO's business plans under RIIO-T1 could be used to set out an approach to optimise investment to manage gas shrinkage that is in the consumers' long-term interest.

Our decision

Business carbon footprint

4.29. We intend to require the gas and electricity TOs to submit an annual report of their BCF. This will be based on the emissions reporting methodology introduced for DPCR5 in 2010. This would also take into account companies obligations to report on emissions to the CRC scheme and other outputs under RIIO-T1. We intend to publish each TOs’ annual carbon equivalent emissions to provide a reputational incentive.

4.30. TOs will be required to report on the emissions related to their business operation according to set categories including building energy usage, operational and business transport and fuel combustion.

4.31. This will include all Scope 1 and Scope 2 emissions[8] on an operational control basis, ie where the TO has full authority to introduce and implement its operating policy. TOs will also be required to report on a subset of Scope 3 emissions, eg business travel and external contractors, to capture the emissions arising from the development and operation of their network, regardless of the legal entity carrying out each activity.

Sulphur hexafluoride (electricity transmission only)

4.32. Over RIIO-T1 we expect companies to install new SF_6 equipment as part of their capex programmes. As a result the total SF_6 mass used in transmission equipment could be twice as large at the end of RIIO-T1 than it is currently.

4.33. We intend to introduce an output on TOs against the SF_6 emissions from their networks. This output is intended to prompt companies to take into account the environmental costs of SF_6 equipment that have different leakage rates. A starting point for companies to make this assessment is their business plans for future capital expenditure. Ideally companies would procure SF_6 equipment with a leakage rate

[8] Scope 1 are direct GHG emissions that occur from sources that are owned and controlled by the company. Scope 2 are indirect GHG emissions from the generation of purchased energy consumed by the company. Scope 3 includes other indirect GHG emissions that result from the activities of the company, but are not owned or controlled by the company.

that is consistent or better than the one per cent per annum recommended by the International Electrotechnical Commission.[9]

4.34. We expect companies to set a baseline in their business plans for SF_6 emissions from their networks over RIIO-T1. Companies should use existing emissions as a starting point and also include adjustments for: (1) a reduction in legacy emissions owing to some replacement of older leaky units with new equipment with best practice leakage rates, and (2) new SF_6 equipment with best practice leakage rate installed as part of load related investment.

4.35. Companies will report annually on their leaked SF_6 emissions and receive a reward or penalty for the deviation from their baseline. We intend to apply a symmetric marginal incentive for the carbon equivalent emissions based on the prevailing non-traded annual carbon price recommended by the Department of Energy and Climate Change (DECC).[10]

4.36. We do not expect companies to set a baseline of zero but instead to converge to best practice level of less than one per cent leakage. At low levels, SF_6 emissions can be lifetime neutral in terms of GHG because the smaller sized installations can be located closer to load and contribute to fewer losses. Because SF_6 installations have a smaller footprint they can also be easier to obtain planning consents for.

4.37. This proposed output moves away from the approach in TPCR4 that sets an annual target rate for companies and gives an upside only financial reward if they achieve the target (the annual target is expressed as a percentage of the total SF_6 mass on the network and the reward was 0.2 per cent of base revenue).

Transmission losses (electricity transmission only)

4.38. TOs influence transmission system losses through investment choices in network infrastructure. There is a close to constant relationship between losses and TOs' actions once assets are in place. The biggest determining factor for volume of losses is the system loading (a positive non linear relationship), which under BETTA is a separate role of the SO.[11]

4.39. As proposed in December, we have looked at losses as part of our work to align SO and TOs incentives. We do not think that greater interaction between the TO and SO would deliver significantly more efficient outcomes in relation to losses. It appears that the SO and TO are able to optimise the impact of their actions or investment decisions on losses independently. Therefore, we do not see there being

[9] The International Electrotechnical Commission prepares and publishes International Standards for all electrical, electronic and related technologies collectively known as "electrotechnology".
[10] DECC set non-traded carbon value for each year out to 2100. DECC's long term non-traded carbon values will be reviewed every five years starting 2011.
[11] In 2005 the British Energy Trading and Transmission Arrangements were introduced and created a single wholesale electricity market for Great Britain with a single transmission system operation (NG) independent of generation and supply.

any significant alignment issues if we put an output on the TO and retain separate incentives on the SO as is currently the case.

4.40. As part of developing their business plans for future capital expenditure we expect TOs to take into account the lifetime costs, including transmission losses when deciding between different transmission equipment. When putting together their submissions we expect TOs to assess whether it is in the long-term interest of consumers to invest in a higher cost/lower loss investment option. The TOs investment appraisal should consider the net present value of the additional cost of a low loss option against the benefit of reduced losses over the lifetime of the asset valued at what consumers pay for losses on the system, ie wholesale price per MWh of electricity lost.

4.41. We intend to include an output on TOs against the modelled lifetime net benefits to consumers (in MWh) arising from low loss investments on their network over RIIO-T1. The counterfactual is where companies did not have regard to losses. We consider this measure is appropriate because: (1) it is a relatively simple metric for TOs to model, and (2) it indicates the net benefits in terms of avoided losses the TO has delivered in consumers' long-term interest. We will require companies to provide information as part of their business plan on the modelled avoided losses with an explanation of their investment appraisal process and working assumptions, eg value of losses, loading of the network.

4.42. We do not think it is appropriate to set a primary output on the actual volume of losses on a TO’s system because: (1) actual losses are unlikely to show the impact of a TO’s low loss investment on the system due to significant volumes of generation locating on the edge of the network, and (2) it would be very complex to derive the change in the actual volume of losses attributable to the low loss investment, ie it would involve year-round power system modelling. Therefore, exposing TOs to costs of actual losses would present a disproportionate risk to companies and consumers.

4.43. We consider it is appropriate to apply a reputational incentive to this output as it is modelled. Companies will provide information at the start of the price control and also report on the modelled avoided losses at the end of price control. Companies might face financial consequences for non-delivery if variations to the baseline are not explained. Companies may be able to earn some financial reward for reducing network losses that is in addition to their baseline activity if we introduce a financial incentive on a broad environmental output following consultation.

4.44. The main purpose of setting an explicit output is to ensure that companies, as part of their network planning practices, fully assess the lifetime costs, including losses, that is in the long term interests of consumers. A specific output in this area will also give greater visibility to customers of TOs’ capex programmes on network efficiency.

Gas shrinkage and natural gas venting

4.45. We have considered gas shrinkage and natural gas venting as part of our work looking at the alignment of SO and TO incentives. We think NGG could potentially deliver long-term net benefits for consumers by optimising the management of gas shrinkage and methane venting across both its TO and SO roles.

4.46. Currently, NGG as SO has an annual incentive to manage natural gas emissions arising from the venting of compressors on the NTS. Under the incentive NGG receives/makes payments equivalent to the costs of emissions, based on DECC's non-traded price of carbon, that are below/above a volume target level.

4.47. NGG as SO also has an incentive to reduce the costs it incurs in procuring gas shrinkage on the system. This three year scheme has an annual cap with a 25 per cent/20 per cent sharing factor for any over or under spend relative to its overall cost target. NGG as TO does not currently have any incentives in relation to gas shrinkage or methane venting.

4.48. The current SO incentives are relatively short term. As a result NGG does not have an economic incentive as either SO or TO to consider the longer-term costs and benefits of potential options for reducing shrinkage and venting. This means that consumers could miss out on investments that have higher upfront costs but might result in lower total system costs of managing these outputs over the longer term.

4.49. In a recent consultation on NGG SO incentives we said that we are considering ways to improve incentives on NGG as both SO and TO from 1 April 2013.[12] We also said that we consider it appropriate for NGG as SO to take full responsibility for the environmental costs of natural gas venting in the long term. To inform our thinking on the development of an appropriate natural gas venting incentive from April 2013 we proposed a new licence requirement on NGG to develop and undertake further work on the measurement of emissions as well as research into the alternatives to venting.

4.50. In light of the forward work programme to develop longer term and sharper SO incentives on NGG we do not consider that it is necessary or appropriate to include additional primary outputs on NGG as TO for gas shrinkage and methane venting under RIIO-T1. Doing so might risk double counting the same output under NGG's different roles. We will consider in June, as part of our work on SO incentives, the economic incentives to encourage NGG to take a more strategic approach across its actions as SO and investment options as TO that are in the long term interests of consumers.

[12] National Gas Grid System Operator Incentives from April 2011: Final Proposals http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=NGG%20SO%20Incentives%20-%20April%202011%20-%20Final%20Proposals%20Consultation.pdf&refer=Markets/WhlMkts/EffSystemOps/SystOpIncent

4.51. In addition, we will require NGG as TO to identify in their business plan for RIIO-T1 operational and capex options to support the SO initiatives for reducing shrinkage and venting. This might include how it will work on an ongoing basis to identify and take forward investment solutions which are beneficial for reducing shrinkage and venting as they arise over the price control. NGG as TO will need to justify the investments and explain how its investment appraisal process contributes to the long term interests of consumers, ie achieves lower total system costs overall.

4.52. We will also consider, as part of the longer term SO incentives, additional mechanisms to allow the SO to identify where capital expenditure solutions might deliver greater benefits for consumers.

Wider environmental footprint

4.53. Transmission infrastructure can have impacts on local landscape, habitat, visual amenity and noise levels. These impacts can, in some instances, be difficult to value. Over RIIO-T1 there will be a significant expansion of electricity transmission networks to deliver the UK's sustainable energy sector. We might see public reluctance to accept the impacts of these networks and TOs having to do more to address the wider environmental footprint of their network.

Summary of consultation proposals

4.54. We did not propose outputs on the impacts of transmission networks on visual amenity or permitted activities such as emissions to water or landfill. This is because the former is primarily dealt with through planning processes. And TOs' compliance with the latter are subject to various environmental regulations enforced by local authorities or the Environment Agency.

4.55. We did recognise, however, that TOs might have to consider the socio-environmental impacts of their network developments at an earlier stage given the new planning regime in England and Wales and work with stakeholders on developing acceptable options. We offered to work with stakeholders, including DECC, to develop guidance for TOs on considering the broader costs and benefits, including environmental impacts when planning network developments.

Summary of responses

4.56. In response to the December document some environmental stakeholders have told us that RIIO-T1 is ignoring an important issue that will only be amplified over the price control. They are particularly disappointed that we were not looking to use explicit elements of the new RIIO framework to require companies to consider better the visual amenity impacts when planning network developments. The specific criticisms we have heard are that the proposals did not:

- propose a specific visual amenity output measure

- include an undergrounding allowance similar to DPCR5 to address impacts of existing lines in National Parks (NPs) and Areas of Outstanding Natural Beauty (AONB)
- commission any new research on national willingness to pay to include both use and non-use values
- consider new cost data on undergrounding options.

4.57. In addition, environmental non government organisations also asked about the scope under the new regulatory framework for network companies to compensate communities affected by network development.

4.58. We have met with DECC to discuss this issue and how to encourage companies to consider better the broader environmental costs and benefits of their network investment proposals. DECC do not think that it is appropriate to include a specific output around visual amenity given it is the responsibility of the relevant planning authority to decide in respect of planning applications for transmission infrastructure.

Our decision

4.59. It is in the interests of existing and future consumers that TOs efficiently address public concerns about proposed network developments. Consumers would benefit from less costly planning applications, as well as timely delivery of critical infrastructure to reduce constraints on low carbon generation, lower the carbon intensity of generation and contribute to security of supply.

4.60. The Gas and Electricity Markets Authority ("Authority") has specific statutory duties under the National Parks and Access to the Countryside Act 1949 (as amended by the Environment Act 1995), the Countryside and Rights of Way Act 2000 and the Norfolk and Suffolk Broads Act 1988 to have regard to the purposes for which these areas are designated, which includes the purpose of conserving and enhancing the natural beauty of the areas. The Authority must also have regard to the purpose of conserving biodiversity under the Natural Environment and Rural Communities Act 2006.

4.61. In response to stakeholders' requests for a measure in RIIO-T1 reflecting the Authority's statutory duties in relation to designated areas we intend to introduce an allowance per TO to reduce the visual impact of existing infrastructure in NPs and AONBs. The amount of the allowance will be based on consumer willingness to pay analysis. We expect companies to undertake this analysis with consumers over a range of mitigation options, eg by tree planting near substations through to undergrounding of lines. Companies should provide information on consumer willingness to pay as part of their well-justified business plans to help inform the value of the allowance that would be appropriate over RIIO-T1.

4.62. Ofgem will continue to consider companies' requests for funding allowances for new infrastructure on a case by case basis. This is because the considerations relevant for the Authority's decision will depend on the circumstances of the individual project. This includes the project's environmental impacts in terms of wider footprint as well as potential contribution to low carbon goals, the designation of the area through which proposed infrastructure is routed, as well as the expected capital and operating costs of the new infrastructure. The Authority will consider requests by reference to all its statutory duties, including its principal objective of protecting consumer interests as well as other duties under the Electricity Act 1989 to contribute to the achievement of sustainable development and to have regard to the impact of transmission activities on the environment.

4.63. As proposed in December, we are providing additional information for TOs in the business plan guidance on demonstrating how they have considered the socio-environmental impacts of proposed developments. We recognise that under the new planning regime in England and Wales companies will have less opportunity to iterate proposed developments after they have submitted an application to the Infrastructure Planning Commission (IPC). The guidance is intended to reduce the risk of a delay to critical investments in the absence of more information about how the IPC will evaluate visual amenity impacts with respect to applications for major transmissions projects.

4.64. The guidance will prompt companies to demonstrate the needs case to support funding requests. We will set out expectations that companies consider and provide supporting information where relevant such as previous planning decisions relating to the conservation of landscape amenity values, stakeholders' views, the costs of different delivery options as well as the criticality of the infrastructure for meeting the UK's low carbon objectives.

5. Customer satisfaction output

Chapter summary
This chapter sets out our strategy decision on the outputs for customer satisfaction. We also set out our decision on how we expect the incentives to be applied.

5.1. We have decided to put in place a primary output that relates to customer/stakeholder views of each TO's performance. We will define this in different ways for the different TOs. This will enable the output to reflect the specific circumstances of each TO including the types of stakeholders and customers that can best provide a relevant picture of the company's performance.

5.2. The primary output will be supported by two separate financial incentives. The first, worth up to +/- 1% of allowed base revenue, will be based on results from a customer/stakeholder satisfaction survey. The second will be a discretionary reward available where TOs are able to demonstrate that their effective stakeholder engagement has led to exceptionally positive outcomes for customers. This will be worth up to 0.5% of allowed base revenue.

Summary of consultation proposals

5.3. We proposed to introduce a primary output related to customer/stakeholder views of TO performance in our December document and proposed two separate financial incentives to support this primary output. These were:

- a customer/stakeholder satisfaction survey with a symmetric incentive rate of up to +/- 0.5% of network companies' allowed base revenue
- a stakeholder engagement reward (via a discretionary reward scheme), worth up to 0.5% of network companies' allowed base revenue for each year (upside only).

5.4. In the consultation we noted that further work will be needed by the network companies to develop customer satisfaction surveys. While NG (NG) could build on its own recently developed survey to ensure that it is aligned with the principles that we set out for these surveys, SP Transmission Limited (SPTL) and Scottish Hydro Electricity Transmission Limited (SHETL) will need to design and develop their surveys from scratch. We committed to working with the network companies to help them develop their surveys over the course of the price control review and noted our expectation that these surveys could be in place for the start of RIIO-T1.

5.5. We presented our views on the way that the discretionary reward for effective stakeholder engagement would broadly work. In this respect, we set out that:

- network companies will be able to apply for the reward on an annual basis
- to be eligible, network companies will need to demonstrate how their effective stakeholder engagement had directly led to better outcomes for consumers
- the assessment will be made by an independent panel. The panel and other governance arrangements would be established by us. We will work with stakeholders to develop these during the review.

5.6. We highlighted that we will develop guidance for the process.

Summary of responses

5.7. Two TOs welcomed the customer satisfaction survey as an effective tool to facilitate understanding of consumer experiences but highlighted that work would need to be done to develop these surveys. The remaining TO, however, had concerns that it may not be possible to develop a robust survey.

5.8. A common theme in responses was that the surveys should capture the views of all network customers. One respondent also suggested that weighting network customer views was important, particularly as the sample size may be small.

5.9. All respondents were supportive of the discretionary reward for stakeholder engagement. One respondent said they would prefer a symmetric incentive with a penalty applied to companies who under performed in this area.

Our decision

Customer satisfaction output

5.10. We expect network companies to develop and further refine customer satisfaction surveys that will be used to set the level of performance for the primary output. It will be important that these surveys and the associated financial incentives are finalised at the point that the RIIO-T1 price control commences. However, we recognise that this is a challenging timescale. The onus is on the companies to develop the surveys but we will seek to help with this process where possible. A key overriding principle for the surveys is that they should provide a depiction of the TOs performance that is as accurate as possible. To achieve this, TOs will need to consult a diverse group of customers and stakeholders and therefore the surveys for each of the TOs will necessarily be different, recognising the differences in their customer bases. For example, SPTL and SHETL will need to provide sufficient information about their role in setting charges and operating the system and their surveys may therefore need to be focused on and/or weighted towards stakeholders connecting to the network or those affected by infrastructure developments. NGET and NGG, and indeed the SO function, will need to report perceptions related to these different functions.

5.11. We would look to apply a financial incentive on NG’s performance in terms of customer satisfaction from the start of RIIO-T1 as they already have a customer survey in place. Given SPTL and SHETL do not have a survey at present, we may need to delay the application of a financial incentive related to their performance in this area, but we will work with them prior to their business plan submissions in July to determine the best way forward. We expect this preparatory work to be completed before 1 April 2013. If, at all, there may be testing to do beyond 1 April 2013. To make sure this testing is completed we would include a licence provision requiring its completion by a set date within the control period.

5.12. We have increased the level of the financial incentive attached to the survey to an equivalent of +/-1% of allowed base revenue per annum. This is because of the:

- need to create a step-change in network company behaviour with respect to their performance in monitoring and driving customer satisfaction
- way it reflects a range of elements of outcomes that are otherwise difficult to define through output measures
- way the incentive (particularly in the case of the Scottish TOs) will reflect the quality of their performance in developing connections.

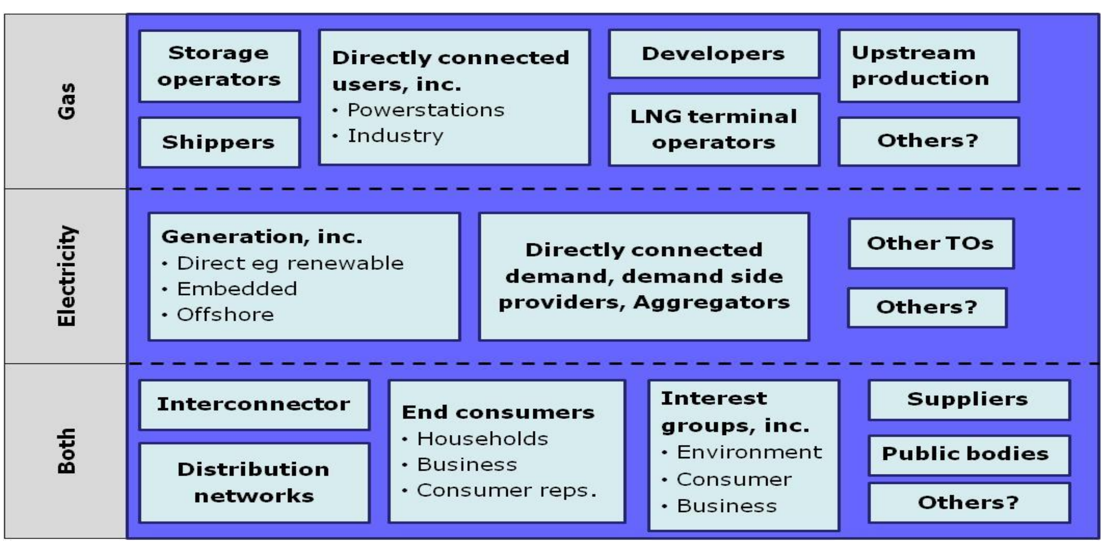
5.13. We recognise that it will take time for the TOs to develop a robust survey to allow us to measure customer satisfaction and set an appropriate output baseline. As such a lower level of incentive may apply at the start of RIIO-T1. We set out below how we will work with network companies to design and apply this financial incentive.

Developing the surveys

5.14. Stakeholders raised concerns that the surveys will be too narrowly focused on a few customer groups and therefore will not reflect the range of customer experience. However, we expect TOs' surveys to cover a wide range of customers. We recognise that given the limited relationship that TOs have with their end consumers (households and businesses) it would not be possible to capture directly their views in surveys and therefore representative bodies are likely to play an important role. The surveys should also capture the views of parties developing new technologies who might have an important insight into TO performance.

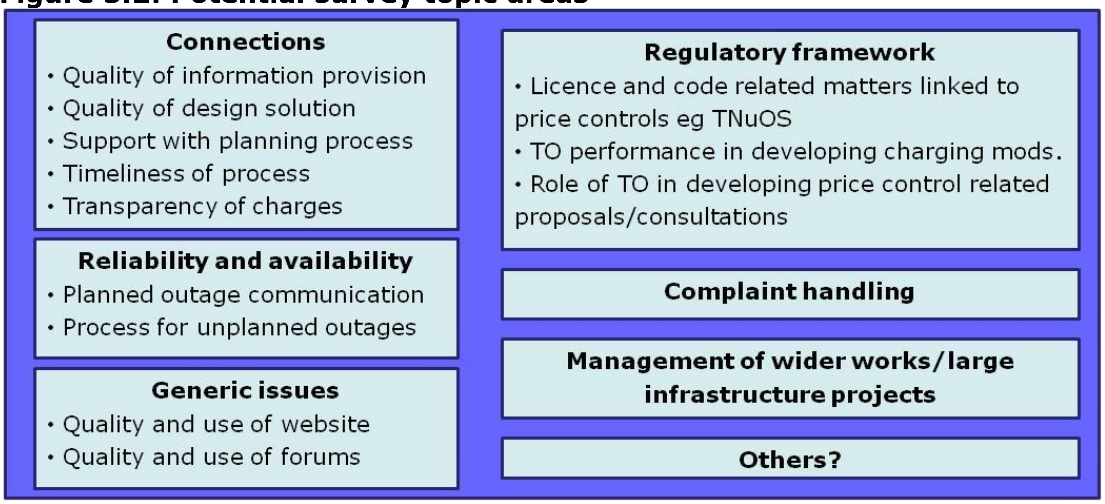
5.15. Figure 5.1 below shows the broad range of stakeholders that might be considered as the TOs develop their surveys. The majority of these stakeholders were captured within NG's recently developed customer survey.

Figure 5.1: Potential customer coverage of network companies' surveys



5.16. Given the range of customer groups that should be captured by the survey, we expect questions to be relevant to the range of activities that the TOs perform for these different customer groups. The questions should be focused on factors that deliver improved customer satisfaction but which are not directly incentivised elsewhere in the price control. Figure 5.2 below sets out some examples of areas that the surveys might cover which is partly based on the question areas identified by NG in their recently developed survey.

Figure 5.2: Potential survey topic areas



Timetable for survey development - SPTL and SHETL

5.17. In their July business plans we expect SPTL and SHETL to have considered fully the structure of their surveys, including the groups of consumers that they need to survey as well as the areas of service and questions that would be appropriate to ask (see Figures 5.1 and 5.2 above).

5.18. In October 2011, we will publish our initial views on network company business plans and the network companies that may qualify for fast-tracking (see Appendix 2 of the overview paper for a detailed RIIO-T1 timetable). At this point, we will set out a broad timetable for the implementation of the customer satisfaction financial incentive in the price control, including when we expect a financial incentive to apply. Paragraphs 5.20 – 5.22 provides further information with respect to our current thinking regarding the application of a financial incentive. As set out above, the network companies will be responsible for developing the surveys but we will work with them to do this.

Timetable for survey development - NG

5.19. We will work with NG to develop further the customer satisfaction survey they have recently compiled. We expect them to have discussed the design and scope of their survey with their stakeholders and submit it for approval as part of their business plan in July 2011. We also expect them to provide a timetable setting out how they plan to develop, test and set an appropriate output level which will apply from the start of RIIO-T1. We will work with them in these areas including on the decision regarding the time from which a financial incentive will apply.

Financial incentives attached to survey performance

5.20. As outlined above, given the time it will take to develop appropriate customer satisfaction surveys to underpin this primary output, it is unclear when the TOs will be able to set a credible output baseline for the price control period. We recognise that it will not be possible for them to achieve this in time for their business plan submissions in July 2011. We are therefore reluctant to apply a financial incentive until we are confident that the survey is robust. For the survey to be robust it must:

- capture all relevant customers
- contain appropriate questions
- have been adequately tested, such that a credible output level can be set
- be appropriately weighted across customer types and questions (if need be).

5.21. While it is likely that the TOs will be able to develop a survey in time for the start of RIIO-T1, we may need to delay the application of a financial incentive or apply a lower incentive rate until there is more certainty about the output data from the surveys. We expect the network companies to provide a timetable, in their business plans, including details of how they plan to develop, test and set an appropriate output level on which a financial incentive can be set.

5.22. In December we suggested that the customer satisfaction financial reward/penalty should be evenly weighted between absolute performance over the course of the price control and the improvement or deterioration in performance as compared with previous years. Discussions with stakeholders and TOs since publication of the December document, including at our stakeholder meeting of 14 February 2011, have highlighted that this is the right approach in principle. We will determine the precise weighting once surveys have been fully developed and trialled.

Stakeholder engagement reward

5.23. The customer satisfaction primary output will include a mechanism to reward companies that can demonstrate that their engagement activities have led to exceptionally positive outcomes for customers over the price control period. It will be considered on an annual basis.

5.24. We do not believe that it is possible to specify all the activities and outcomes that would determine eligibility for this reward. Indeed, we see this as undesirable as we do not want to constrain the network companies in their approach to improving outcomes for their customers. For this reason, the assessment of whether to grant a reward (and the level of that reward) will need to incorporate a certain degree of judgement and qualitative appraisal. As a result, we do not believe that it is appropriate to introduce a financial penalty for companies that perform less well in this assessment.

5.25. We will attach a discretionary financial incentive to performance in this area worth up to 0.5% of allowed base revenue. The size of this reward reflects the importance we place on the TOs being able to anticipate and respond to the needs of stakeholders throughout RIIO-T1.

5.26. In assessing networks companies performance in this area we will focus on the outcomes achieved for customers rather than the engagement process itself. We will set minimum requirements that networks companies' must meet before being considered for a reward. These will require that the TOs:

- have a clearly defined strategy for engaging with a range of stakeholders
- ensure they have consulted a range of stakeholders and allowed them to comment on the approach to engagement taken by the network company
- to adapt processes and policies in response to feedback from stakeholders.

5.27. We will work with industry to develop our thinking on the appropriate method of assessing performance in this regard and to consider the details of how the process will work. We will also draw on the lessons learnt from the stakeholder engagement element of the broad measure of customer satisfaction applied in electricity distribution as part of DPCR5 - which will be developed in 2011 and 2012. The incentive for RIIO-T1 will be in place for the start of the price control along with guidance on how to apply for it.

6. Reliability and availability - electricity transmission

Chapter Summary
This chapter sets out our strategy decision on primary outputs and secondary deliverables for reliability and availability for electricity transmission during RIIO-T1. We also set out our decision on how incentives should be applied to these.

6.1. The primary outputs and secondary deliverables for reliability and availability are largely unchanged from our initial proposals.

6.2. For electricity transmission, the primary reliability output for all TOs is energy not supplied (ENS). We have refined our approach to exclusions from the ENS incentive, including the treatment of events on adjacent systems and the removal of the exclusion for planned outages in the current Network Reliability Incentive Scheme (NRIS).

6.3. We will apply a common incentive rate, with a strength in the range £4,300-£22,000/MWh adjusted by the efficiency incentive rate.[13] We have reconsidered our proposal to remove the collar on the financial penalties for ENS taking account of responses to our consultation. We consider that it is appropriate to have a common collar on the incentive of 3% of allowed revenue so that the TOs are not exposed to a disproportionate level of risk under ENS or the full incentive package.

6.4. In light of applying a collar on the incentive scheme, we have decided that we will enforce a minimum standard of performance through a licence condition. In circumstances where a TO's performance triggers the collar, it would be required to demonstrate that it had taken all reasonable preventative and mitigating actions both before and after loss of supply events to minimise unsupplied energy. Where we consider that the TO has not done this, we would have the option to commence licence investigation procedures and, where appropriate apply a financial penalty.

6.5. We have decided to use a suite of secondary deliverables to ensure any risk to long-term delivery of the primary output is managed and that they deliver value for money for existing and future customers. The TOs and wider stakeholders have indicated broad support for secondary deliverables in four areas:

- asset health, criticality and replacement priorities (risk)
- system unavailability and average circuit unreliability (ACU)
- faults
- failures.

6.6. Two respondents raised concerns about our proposed changes to the definitions of asset health and replacement priorities that better align with DPCR5 definitions. We have taken these into account in reaching our final decision.

[13] This figure will be maintained in real terms over the price control period.

6.7. We will apply a symmetric approach to incentives for the delivery of asset health, criticality and asset risk. The agreed secondary deliverables will form the starting point for the next price control review. As part of their business plans TOs will then be able to consider whether the secondary deliverables should be improved for RIIO-T1.

6.8. We will assess whether the TO has performed satisfactorily and delivered the reduction in asset health related network risk it agreed to deliver over the course of RIIO-T1 and carry forward the agreed baseline secondary deliverables to the next control period. Network companies should be able to recover their share of the over spend (under the IQI incentives) relating to over delivery if they can demonstrate this is positively valued by customers, and that the costs incurred were efficient. Similarly, we would look to recover the under spend if the TOs are not able to demonstrate this. We consider that this approach is consistent with the RIIO recommendations and the longer-term approach to price controls.

6.9. We intend to take forward an approach for aligning the relevant SO and TO incentives to ensure that they work together to deliver efficient and economic outcomes in the management of short-term constraints. We will ask a specific question in the business plan guidance to require TOs to justify how they intend to work with the SO to manage their impacts on short-term constraints. We intend to introduce an incentive regime to enable the SO to incentivise (eg via payments) the TO to change its behaviour.

6.10. The following section provides background and context to setting reliability and availability outputs. We then present our strategy decision for:

- the primary output and incentives on ENS
- secondary deliverables and associated incentives
- incentives to optimise constraint costs arising from electricity TO activities.

Background and context to setting reliability and availability outputs

6.11. Under TPCR4, electricity TOs are subject to the Network Reliability Incentive Scheme (NRIS). This provides them with rewards/penalties for over/under performing against target levels of unsupplied energy (NGET) or the number of loss of supply events (SPTL and SHETL).

6.12. The NRIS was implemented in 2005-06 following two transmission failures in London and Birmingham. Whilst the current scheme has provided a starting point for developing a primary output, we considered it appropriate to re-examine several of the assumptions underpinning the scheme (including the definitions of several exclusions) and progress this work as part of the safety and reliability industry workshops.

6.13. The stakeholder working group also explored similarities between the DNOs Interruptions Incentive Scheme (IIS) (which is based on customer interruptions (CI) and customer minutes lost (CML)) and the NRIS based on ENS. We feel that it is important to align the treatment of particular loss of supply events between the schemes, where possible.

6.14. We have also examined the Network Output Measures (NOMs) in relation to asset health and criticality taking into account similar work that was carried out as part of DPCR5. The NOMs provide a useful starting point for secondary deliverables for RIIO-T1.

Primary output on ENS

Summary of consultation proposals

6.15. Our consultation proposal was that the primary output for electricity transmission reliability should be ENS. This represented a change for SPTL and SHETL that are currently incentivised on the number of interruptions but not for NGET that is currently incentivised on ENS under the NRIS. We noted that duration of events used for calculating ENS would end when the Scottish TOs advise the SO that the network elements necessary for restoration are available.

6.16. In our December document proposals, we set out our initial views on the types of events that would be excluded from calculating incentivised ENS. In summary, these are:

- Loss of supply events in the current NRIS that are largely outside the control of the TO would continue to be excluded. These events are:
    - any unsupplied energy resulting from a shortage of available generation
    - any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code
    - any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the SO to the licensee pursuant to the Systems Operator Transmission Owner Code (STC).
- Loss of supply events lasting three minutes or less should be excluded as these largely relate to the correct operation of delayed auto-reclose (DAR) which could be assumed to cover events for which the cause is weather.
- Loss of supply events that result in unsupplied energy to parties that have lower standards of connection should be excluded. This is different to the current NRIS that uses three or less directly connected parties as a proxy for customers with a lower standard of connection.
- Loss of supply events caused by actions to ensure public safety, third-party damage, severe weather and other exceptional events would not be automatically excluded. TOs would need to demonstrate that they have met specified exceptionality requirements for an adjustment to be made to the incentivised level of ENS.
- Loss of supply from planned outages should not be excluded.
- Loss of supply events triggered on adjacent systems should not be excluded. A framework should be developed to enable the TOs to equitably share the total

incentivised ENS across all of the networks that contributed to the energy not supplied. This share should also reflect the role of the SO in restoring supply.

Summary of responses

6.17. Respondents broadly supported our proposal that the primary reliability output for all TOs should be ENS. One respondent noted that their agreement based on agreeing appropriate exclusions to the scheme and another noted that that the incentive structure should reflect the risk of the businesses. One respondent argued that our reliability outputs should better take account of the TOs providing a system with a predefined level of security.

6.18. Most respondents supported our proposals on the types of events that should be excluded when calculating ENS, subject to the following:

- One respondent noted that amending the exclusions relating to unsupplied energy to three or fewer customers to reflect only those customers that have requested lower standards of connection may complicate the benchmarking of historical performance and also questioned the difference in severe weather thresholds between NGET and the Scottish TOs.
- One respondent argued that only controllable events are included in the calculation while another argued that ENS is not directly within the control of the Scottish TOs.
- One respondent argued that planned outages should continue to be excluded but noted that these events are unusual and reduced levels of supply are negotiated individually with the customer.
- One respondent disagreed with our proposed treatment of events triggered on adjacent systems and argued that the DNO IIS is more appropriate (under the DNO IIS, DNOs are penalised for zero per cent of customer interruptions and 10 per cent of customer minutes lost).

6.19. One respondent also sought clarity on the issues that we will consider in assessing whether the baselines proposed by the companies are acceptable or need to be changed.

Our decision

6.20. Our strategy decision is that the primary reliability output for all TOs should be ENS. ENS is readily measurable, is controllable over the long term and, can be consistently measured and compared. It is the most applicable metric as it incorporates the frequency and duration of interruptions and the associated load that is affected, providing a measure that reflects the ultimate output delivered to customers.

6.21. We note the views from one stakeholder that it would prefer maintaining the current Scottish scheme based on the number of events, but consider it important for all TOs, including SPTL and SHETL, to be incentivised on a consistent basis and on a basis that incorporates both the number of outages and the volume of load that is interrupted. An output based only on the number of interruptions does not provide any financial incentive for the TOs to restore supplies as quickly as possible, or to provide contingencies to allow rapid restoration.

6.22. Unlike NGET, SPTL and SHETL do not perform an SO function. We note that the duration of loss of supply events is affected by both the assets and actions of the TO as well as the actions of the SO. We are therefore proposing an output for the Scottish TOs that takes account of this split. For SPTL and SHETL, we propose that the duration of events used for calculating ENS should end when they advise the SO that the network elements necessary for restoration are available.

6.23. For NGET, we propose that the duration of events should be consistent with the current scheme and thus incorporate its role as both TO and SO. To provide greater transparency between the TO and SO functions, NGET should report on a basis consistent with the Scottish TOs – that is, reporting the time taken to make the necessary network elements available for restoration, and separately reporting the time taken for the SO to restore supply.

6.24. The following section outlines how we will treat different types of loss of supply events when calculating our primary output ENS, in particular:

- events that are excluded from the NRIS and will continue to be excluded in RIIO-T1
- events lasting three minutes or less that will be excluded
- events relating to customers with a lower standard of connection will be excluded
- events relating to emergency de-energisation, third party damage, extreme weather and exceptional events will not be automatically excluded
- events relating to planned outages that will not be excluded
- events on adjacent systems that will not be excluded.

Events under current NRIS that will continue to be excluded in RIIO-T1

6.25. We have decided that the following exclusions in the current NRIS be maintained:

- any unsupplied energy resulting from a shortage of available generation
- any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code
- any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the SO to the licensee pursuant to the STC.

6.26. These events are all currently excluded from the NRIS and respondents agreed that they should continue to be excluded. These events are largely outside the control of the TO and hence we consider it appropriate for them to continue to be excluded from the ENS.

Unsupplied energy from events lasting three minutes or less

6.27. Our decision is that the definition of a relevant loss of supply event should exclude events lasting three minutes or less. Respondents agreed that excluding events of less than three minutes duration would allow for the correct operation of delayed auto-reclose (DAR)[14] which is widely used for quick restoration of supplies following transient faults. This exclusion is also consistent with the DNO IIS.

6.28. We acknowledge that interruptions of three minutes or less can have a significant impact on customers. We note the limited control that the TOs have over short duration interruptions. We also note that events lasting for fewer minutes tend to make a small contribution to the total level of ENS. Over the last three years events of three minutes or less accounted for less than one per cent of the total ENS.[15]

Unsupplied energy that causes electricity not to be supplied to three or fewer directly connected parties

6.29. The exclusion relating to unsupplied energy to three or fewer directly connected parties will be amended to reflect only those customers that have requested lower standards of connection.

6.30. This exclusion was part of the original NRIS, designed to act as a proxy measure of events involving a lower standard of connection. Respondents supported our proposal to amend this exclusion although one noted that it may complicate benchmarking of historical information. We understand that this should not be a significant issue and expect that the TOs should be able to capture and assess this information when developing baselines for their well justified business plans.

Unsupplied energy resulting from actions to ensure public safety,[16] third-party damage, severe weather and other exceptional events

6.31. We have decided that unsupplied energy from emergency de-energisation to comply with ESQCR or otherwise to ensure public safety, third party damage, severe weather and other exceptional events should not automatically be excluded from the primary output. We will use a framework similar to the DNO IIS whereby the TOs will need to demonstrate that they have met specified exceptionality requirements for an adjustment to be made to the incentivised level of ENS. For example, in the case of third party damage, for the event to be excluded the TO will need to demonstrate that the event was not attributable to any error on their part and that they had taken all reasonable preventative and mitigating actions both before and after the event.

[14] DAR refers to the automatic re-energisation of overhead lines after transient flashover events such as lighting strike or conductor clashing after a short delay to allow the event to pass.
[15] Source: TO submission to safety and reliability working group 2010. It should be noted that this is based on ENS as defined by the current NRIS.
[16] Emergency de-energisation or disconnection of a user's equipment necessary to ensure compliance with the Electricity Safety, Quality and Continuity Regulations 2002 or to otherwise ensure public safety (exclusion under current scheme).

6.32. Examples of events relating to third party damage and public safety could include a member of the public climbing a transmission tower, notwithstanding the presence of anti-climbing guards, or a fire adjacent to a site where emergency de-energisation was required. TOs estimate that there are approximately two to three events of this nature each year.

6.33. We acknowledge that events of this nature can often be outside the control of the TO and would not want to create a framework that discourages the TOs from taking decisions to ensure the public safety. However, we consider it appropriate that the TOs be provided with some incentive to manage these risks. For example, TOs should be encouraged to learn from these events both on their networks and elsewhere and to ensure that they take reasonable steps to prevent them in future. An automatic exclusion for these events provides no incentive for the TOs to do this.

6.34. Our view is that a framework that is similar to the DNO IIS is more appropriate. For all exceptional events other than severe weather, the TOs will be required to demonstrate that they have met exceptionality requirements, including:

- that the event was a consequence of an external cause
- that they had taken all reasonable preventative and mitigating actions both to limit the number of customers interrupted and to restore supplies quickly and efficiently having due regard to safety and other legal obligations. This should include having taken appropriate risk assessment for key sites.

6.35. We note that the Authority has recently indicated concerns with the current application of the DNO licence condition reflecting these requirements.[17] We have indicated that we will be undertaking an in-depth review of all of the relevant licence conditions in order to ensure that proportionate requirements are on all DNOs to assess and, where appropriate, to take steps to address risk. We would expect the outcomes of this review to be reflected in the transmission scheme for RIIO-T1.

6.36. We have decided to maintain the extreme weather thresholds in the current scheme. The current scheme is based on the number of faults caused by weather in a 24 hour period (50 faults in 24 hours for NGET, seven faults in 24 hours for SPTL and SHETL). The Scottish TOs have different thresholds to reflect the size and nature of their respective networks and we consider that these should be maintained. We also note that there has only been one event of this nature since the introduction of the scheme.

Planned outages (exclusion under current scheme)

6.37. We have decided that there should not be an exclusion for planned outages. This is consistent with our December proposal that any interruptions impacting on customers' load should be incentivised to reflect the impact they have on these customers.

[17] Explanation of Authority's reasons for the direction issued under special condition C2 pursuant to special condition CRC8 – EDF Energy Networks (LPN), plc
http://www.ofgem.gov.uk/Networks/ElecDist/QualofServ/Documents1/EDFE%20LPN%20Reasons.pdf

6.38. The current NRIS excludes events resulting from planned outages as defined in the Grid Code whilst the DNO IIS does not exclude these events. DNOs are currently incentivised on a 50 per cent weighting for customer interruptions (CI) and customer minutes lost (CML). This DNO scheme balances the need for DNOs to be incentivised to minimise the length of planned outages and their requirement to reinforce the network and the reduced impact on customers where they are given advance notice of interruptions. As noted above, it is our view that we should seek to align the treatment of particular loss of supply events between the DNO IIS and the RIIO-T1 output of ENS.

6.39. Respondents have confirmed that planned outages only lead to interruptions to directly connected customers who in most cases have specified a lower standard of connection. These customers would be excluded from the primary output as discussed in paragraphs 6.29-6.30. In the case of the Scottish TOs, there may be unsupplied energy to directly connected customers that have not specified a lower standard of connection, but we note that these events are rare.

6.40. In the event that one of these outages was to lead to loss of supply for the customer, we would include 50 per cent of the impact in the ENS incentive. This approach is consistent with the DNO scheme and reflects the element that pre-notification has on the disruptive impact of the outage.

6.41. We also note that we are applying a marginal incentive for ENS around a forecast baseline level of performance. Baseline levels of performance need to be developed based on historical performance as well as forecast build programmes. We would expect the TOs to put forward options on a level of performance that seeks to balance network reinforcement with customer needs and incorporate any forecast impact of planned outages that may impact on directly connected customers (but as noted above, we expect these to be rare).

Events triggered on an adjacent TO system

6.42. We have decided that unsupplied energy resulting from events triggered on another TO system should not be excluded from the incentive. We see no difference in the value that customers would place on these events from events occurring on the TO's own system. We will apply a framework that enables the TOs to share equitably the total incentivised ENS across all of the networks that contributed to the energy not supplied. In the case of events on the Scottish TOs' systems, this share should also reflect the role of the SO in restoring supply.

6.43. We note that there have been two of these events in the last twenty years.[18] One such incident occurred at Windyhill in March 2009. Given the small number of events that have occurred historically, our approach should not create a significant burden on TOs whilst still ensuring that there is an incentive to minimise unsupplied

[18] In this incidence, a catastrophic failure of a piece of equipment at Windyhill 275kV substation caused the loss of supplies to customers at seven Grid Supply Points (GSPs) in the Windyhill group and multiple locations on the SHETL network.

energy to customers regardless of whether the fault occurs on their transmission network or that of an adjacent network. It will also avoid double counting of ENS.

6.44. The sharing mechanism will be based on the following principles:

- In the first instance, the TOs and SO would have the option to agree mutually an allocation of the total pool of unsupplied energy.
- In the case of events on the Scottish TOs' systems, the share should reflect the role of the SO in restoring supply. We do not intend unsupplied energy resulting from the SO's role in restoring supply on the Scottish networks to be included in NGET's primary output. For events on NGET's network, we will further consider the inclusion of unsupplied energy from the SO role in NGET's primary output and interactions with its SO incentives when developing the framework.
- The TOs would need to agree the extent to which the interruption was caused by, or substantially contributed to by, events occurring on an adjacent TO's network. This would be based on the degree of control that each party had over the events that led to the interruption and the duration of the interruption. The TOs would then agree what proportion (up to 100 per cent) of the unsupplied energy from the event should be allocated to the adjacent TO.
- In the event where agreement could not be reached, the Authority would maintain discretion to make a decision on the proportion of energy that should be allocated. The Authority may use an external examiner to make a recommendation on how to apportion the incentive.

6.45. We have asked the TOs to use the Windyhill incident to illustrate how the framework would be applied and expect to refine the approach further before the commencement of the RIIO-T1 price control in 2013-14.

Incentives on Energy Not Supplied

Summary of consultation proposals

6.46. In December we proposed that TOs should be provided with a marginal reward/penalty for over/under performing against target levels of ENS. We proposed that the incentive in £/MWh should be symmetrical and its value should be associated with the value customers place on electricity when they are without supply.

6.47. We also set out our views on other elements of the incentive structure including:

- Removing the revenue neutral dead band around the TOs' target level of performance.
- Removing the collar on the maximum penalty faced by the TOs for under performance. We noted that our strategy decision on removing the collar would be informed by the incentives across the suite of output measures and the potential impact on the overall return on regulated equity (RoRE).

Summary of responses

6.48. Several respondents raised concerns about our proposed incentive structure for ENS. They agreed that the strength of the incentive (in £/MWh) should be reduced to a level more consistent with the VOLL but did not agree with our proposal to remove the collar on the maximum penalty faced by the TOs.

6.49. Several respondents agreed that the current value for incentivising unsupplied energy in the NRIS is too high. One respondent noted that that the debate should be informed by several factors including:

- stakeholder engagement
- Ofgem's review of the security standards
- a comparison of gross domestic product (GDP) with MWh transported in Britain, the cost of disruption caused by loss of supply events and the potential for industry catch up of lost productivity when supplies are restored.

6.50. Other respondents suggested that:

- establishing an appropriate lower level for VOLL should be a priority as it should be an important input to work to develop the SQSS
- a value of £16,000/MWh could be used for the incentive
- the strength of the incentive should reflect the materiality of ENS and the company's risk profiles during the RIIO-T1 period.

6.51. Several stakeholders expressed concern during working groups about our proposal to remove the collar on the financial penalty that they face for under performance. One argued that the collar should be maintained and that a limit of one per cent of allowed revenue is appropriate to maintain symmetry between the maximum rewards and penalties it is exposed to.

Our decision

6.52. The following section discuss the main elements of our ENS incentive:

- aligning the strength of the incentive in £/MWh to reflect better the value customers place on electricity when they are without supply
- adjusting the incentive strength by the efficiency incentive rate
- removing revenue neutral deadbands
- applying a collar on the maximum penalty faced by the TOs.

Aligning the strength of the incentive to reflect better the value customer's place on electricity when without supply

6.53. We have decided to apply a common incentive strength in the range £4,300-£22,000/MWh to all TOs.[19] Our decision has been informed by stakeholder comments and evidence of VOLL applied previously to the GB market as well as in other

[19] This figure will also be maintained in real terms over the price control period.

jurisdictions. In light of our decision to place a collar on the maximum penalty faced by the TOs, we have also balanced the need to incentivise all TOs adequately across a reasonable range of ENS. This range reflects the various estimates of VOLL. We will undertake further work during the price control to decide on an exact value. At this stage, we consider a value of £16,000/MWh to be a reasonable level within this range for the TOs to use to develop their well-justified business plans. However, as set out below this may change as a result of continuing research.

6.54. We will undertake further work during the price control review to set the exact value that will be applied in RIIO-T1. This will consider research that Ofgem will be undertaking in 2011-12 to inform analysis on electricity capacity margins which we are required to carry out under the December 2010 Energy Bill.

6.55. VOLL is defined as the theoretical price that consumers would be willing to pay to maintain supply. Using VOLL to inform the ENS incentive encourages economic efficiency in the TOs' network investments by ensuring an appropriate trade-off between the cost of improving reliability and the value customers place on this improvement.

6.56. As noted in our December document, it is difficult to quantify VOLL. VOLL is affected by several factors that impact on customers' energy use and hence the value they place on supply. These include:

- customer type (for example residential, commercial, industrial) and time of day
- the frequency and duration of interruption
- weather conditions or seasonality.

6.57. There are also various methods that can be used to estimate VOLL that can lead to different results. These include macroeconomic methods (for example dividing gross domestic product (GDP) by energy consumed), customer surveys on willingness to pay and cost estimates based on previous loss of supply events. There tends to be less information available on the latter of these approaches, with previous studies of VOLL focusing on macroeconomic approaches and surveys of willingness to pay.

6.58. We have reviewed research on VOLL including information provided by respondents, values applied previously in the GB market as well as other jurisdictions (see Table 6.1). This review reflects the variability of VOLL by jurisdiction (given different proportions of residential, industrial and commercial customers and customer preferences), method of estimation and context in which the value is applied. It has also confirmed our preliminary view that the current incentive strength applied to NGET (approximately £33,000/MWh) is likely to overvalue VOLL.

Table 6.1: VOLL estimates

Value (2009-10)	Year of study	Jurisdiction
£4,300/MWh	2010	Great Britain
£3,400/MWh	2000/01 (originally based on 1977 study)	Great Britain (pool value for England and Wales based on Finnish study)
£16,000-£19,000/MWh (energy consumption weighted) £3,800-£4,700/MWh (customer number weighted)	1996	Great Britain
>£12,000/MWh	1995	Great Britain (London Electricity)
Industry: £2,600-£3,100 /MWh Services: £3,100-£8,900 /MWh Residential: £13,000/MWh	2007	Ireland
£22,000/MWh	2007	Victoria, Australia
£8,800/MWh	2010	Ireland

6.59. Lower estimates of VOLL (in the range £3,400-£4,300/MWh) are based on the value previously applied in the England and Wales electricity pool and a macroeconomic estimate calculated by dividing GDP by MWh of electricity transported.

6.60. The pool value was originally based on a 1977 Finnish survey of customer willingness to pay and we consider that more recent studies are likely to reflect better the value customers place on electricity when without supply. Several studies have argued that this value was underestimated (for example Newbery 1998). Roques et al (2004) note that this is largely due to the difficulty in estimating the value customers place on electricity security of supply when power outages are rare.[20] The macroeconomic estimate based on GDP and electricity transported can be considered a basic measure of VOLL with one respondent noting that it does not take account of the cost of disruption caused by loss of supply events. Other research indicates that these macroeconomic estimates should at best be considered a lower bound for more reasonable estimates.[21]

[20] Roques et al, Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA, 2004, Available from: http://www.dspace.cam.ac.uk/bitstream/1810/131567/1/ep58.pdf
[21] Cramton and Lien, 2000, Value of Lost Load, University of Maryland.

6.61. Higher estimates of VOLL (in the range £8,000-£22,000/MWh) are supported by other studies.

- The Irish Single Electricity Market used a value of £8,800/MWh in 2010.
- A 2007 Irish study used a production function approach to obtain an estimates of £13,000/MWh for residential customers experiencing short duration outages.[22] We note that other studies have indicated that VOLL tends to increase with time for residential users whose activity depends on electricity, while VOLL tends to decrease for large industrial users that have the possibility to install back up systems or to adapt their activity.[23]
- A 1996 study based on a survey of customers in British Regional Electricity Company areas obtained a range of £16,000-£19,000/MWh when weighted by electricity consumption.
- A 2007 survey in Victoria, Australia produced a weighted average of £22,000 /MWh. We note that this average is based on the unique mix of residential, commercial and industrial customers in Victoria.

Adjusting the incentive strength by the efficiency incentive rate

6.62. In applying the ENS scheme we will adjust the VOLL in £/MWh by the IQI marginal incentive rate. For example, if the efficiency incentive rate is set at 50%, and we set the VOLL at an indicative level of £16,000/MWh the TOs would face a reward/penalty of +/- £8,000/MWh.

Removing revenue neutral dead bands

6.63. We have decided to remove the revenue neutral dead band around the target level of performance that currently applies in TPCR4. We consider that under an eight-year price control, the businesses will be better equipped to deal with short-term fluctuations in performance.

Applying a collar on the maximum penalty faced by the businesses

6.64. There is a natural cap on the maximum reward the TOs can achieve based on zero MWh of unsupplied energy. We have decided to apply a collar of 3% of revenue on the maximum penalty faced by each of the businesses. This will ensure that they are not exposed to a disproportionate level of risk under ENS or the full incentive package.

6.65. In our December document, we noted that removing the collar would strengthen the incentive by exposing the businesses to the full value that customers place on unsupplied energy. We note that this could potentially have significant revenue impacts in the cases of low probability, high magnitude events occurring in any one year, particularly for the Scottish TOs. We have therefore decided that there

[22] This approach relates electricity use to firm output, or in the case of households, the value of time spent on non-paid work.
23 Roques, Newbury and Nuttall, 2004, Generation Adequacy and Investment Incentives in Britain: from the Pool to NETA, Available from: http://www.dspace.cam.ac.uk/bitstream/1810/131567/1/ep58.pdf

should be a limit on the exposure to this incentive, subject to a minimum standard of performance imposed through a licence condition.

6.66. In our December document we also noted that if a collar were applied, we would consider whether a licence condition should apply to ensure a TO's performance deteriorating beyond the collar. We have decided that we will enforce a minimum standard of performance through a licence condition. In circumstances where a TO's performance triggers the collar, it would be required to demonstrate that it had taken all reasonable preventative and mitigating actions both before and after loss of supply events to minimise unsupplied energy. In cases where we consider that the TO has not done this, we would have the option to commence licence investigation procedures.

6.67. We have reached a decision on the level of the collar by considering:

- the context in which the current cap was set and how it is impacted by our change to the incentive rate (in £/MWh)
- the resulting range of ENS over which the businesses will be incentivised and the likelihood of the businesses to reach the cap based on historical performance
- the impact of an unlimited penalty on the revenue and RoRE of the businesses.

6.68. Under the NRIS, NGET's penalty is limited to 1.5% of revenue while SPTL and SHETL are limited to 0.75% of revenue.[24] These limits were first introduced mid way through a price control period and in the case of SPTL and SHETL with only two years of the price control remaining. Over a longer-term price control, the businesses should be better placed to manage the risk associated with over and under performance against their target levels. On balance, we consider a higher level of revenue exposure than the current scheme is more appropriate.

6.69. Increasing the penalty from 1.5% to 3% increases the effective range of ENS over which the businesses will be incentivised. We have sought to maximise the ENS range over which the businesses will face an additional monetary penalty per MWh of under performance whilst balancing the level of RoRE risk.

6.70. We have considered historical data on unsupplied energy to understand the likelihood that the businesses will face a collared penalty.[25] It is our view that the collar should be set at a level that provides protection for low probability, high impact events. Based on an incentive rate of £16,000/MWh adjusted by a 50% efficiency incentive rate,[26] a 3% collar would only have been triggered once in the last 20 years for SHETL and not at all for NGET and SPTL.[27]

[24] As noted above, these limits currently apply to the number of loss of supply events.
[25] This data is based on total unsupplied energy and does not reflect the RIIO-T1 exclusions outlined in this chapter. This means that these estimates are likely to overestimate the historical incentivised levels of ENS.
[26] For indicative purposes.
[27] These estimates are on the basis of the increase in revenue allowances currently being forecast by the businesses.

6.71. We have also examined the likely RoRE impact of different levels of the collar. We consider that a collar of 3% provides a reasonable level of risk to RoRE for the businesses.

Secondary deliverables

Summary of consultation proposals

6.72. Our consultation proposal was that we should use a suite of secondary deliverables to ensure any risk to the longer-term delivery of the primary output is managed and the TOs deliver value for money for existing and future customers. These were:

- asset risk (asset health, criticality and replacement priorities)
- system unavailability and average circuit unreliability (ACU)
- faults
- failures.

6.73. We also noted that we expect the TOs to pursue a system-wide risk assessment in the longer term to justify investment in assets that impact on the reliability and safety of the network or on the environment.

Summary of responses

6.74. Respondents supported our consultation proposal for secondary deliverables relating to asset health, criticality, replacement priorities/risk, system unavailability, ACU, faults and failures. Two respondents are opposed to our proposed changes to the NOMs to reflect RIIO-T1 secondary deliverables.

6.75. One respondent does not support changing the ordering of priority from lowest "1" to highest "4" across asset health, criticality and replacement priorities/risk. It also considers that its current internal definitions of asset health are more appropriate and that these should continue to be mapped to the definitions in the NOMs. Furthermore, it prefers the use of replacement priorities indicating the timescales in which the asset should be replaced rather than a risk index arguing that they are more helpful in communicating how it builds its capital plan. This respondent is also concerned about how easily system availability can be forecast.

6.76. Another respondent argued that because the asset health definitions were only recently agreed in the NOMs, further changes should not be suggested at this time.

6.77. One respondent noted that it is not possible to sum the individual secondary deliverables together to form a single meaningful risk measure.

Our decision

6.78. Our strategy decision is unchanged from our initial consultation proposal. We will use secondary deliverables relating to asset health, criticality, replacement priorities (or risk), system unavailability and ACU, faults and failures.

6.79. These secondary deliverables are the same as those used for our safety outputs and provide a framework for managing network risk including safety, reliability and environmental implications.

6.80. As noted in our December document, the TOs currently report on each of these deliverables under Standard Licence Condition B17 Network Output Measures (NOMS). We are maintaining the current reporting for criticality, replacement priorities, faults, failures, system availability and average circuit unreliability. However we have decided to make changes to how asset health is reported. Appendix 2 contains further information on our decision to amend the reporting of asset health and criticality reporting requirements.

6.81. We maintain our view that, in the long term, the TOs should pursue a system-wide risk assessment to justify investments in assets that impact on the reliability and safety of the network or on the environment. We recognise that the TOs make asset management decisions trading off factors such as deliverability, resourcing and consistency with wider outage plans. We consider it important that they have a more consistent framework for articulating this. We do not necessarily expect that this measure would be simply derived by adding the individual secondary deliverables.

6.82. In the short term (including in RIIO-T1), we expect the businesses to be able to articulate how they use other risk management processes in conjunction with our proposed secondary deliverables when making asset management decisions. This should demonstrate:

- how the TOs make the case for spending a marginal pound across different asset categories (for example, they should describe how risk trade-offs are made between different assets)
- how trade-offs are made between areas of expenditure (load, non-load, capex and opex).

6.83. We expect the TOs to continue developing a broader risk metric in the medium to longer term.

Incentives on secondary deliverables

Summary of consultation proposals

6.84. Our consultation proposal was that we should apply an incentive framework to secondary deliverables that requires the TOs to demonstrate how their expenditure is linked to managing network risk at both the beginning and end of the price control period. This involved the TOs setting out risk indices for each of their major asset types as they stand currently and as a forecast for both the middle and end of the price control period, with and without intervention. We would then undertake a performance assessment at the end of the price control period to determine whether each TO has performed satisfactorily in delivering the level of asset network risk it agreed to deliver over the RIIO-T1 control period.

6.85. We considered that financial incentives should apply in cases where there is material under or over delivery. We sought comment on two options for how these incentives could be applied:

- the DPCR5 approach, where a revenue adjustment is made at the end of RIIO-T1
- an approach that involves us beginning the next price control on the assumption that the TOs have achieved agreed levels of asset risk.

6.86. We also consulted on whether the incentives imposed on secondary deliverables should be asymmetric, ie penalty only.

Summary of responses

6.87. Two respondents agreed that financial consequences should apply to secondary deliverables in both cases of over and under delivery against agreed outputs. Other comments included that:

- our assessment of material over and under delivery should be made by considering all of the secondary deliverables and not be measured purely in terms of asset replacement volume
- it is inappropriate to benchmark performance between the TOs
- the assessment should consider the level of access that is made available by the SO to the TOs for undertaking asset replacement and refurbishment.

6.88. No stakeholder commented on which of our two options for applying financial consequences was preferred.

Our decision

6.89. We consider that it is appropriate to apply a symmetric approach for over and under delivery of the secondary deliverables. Network companies should be able to recover their share of the overspend (under the IQI incentives) relating to over delivery if they can demonstrate this is positively valued by customers, and that the costs incurred were efficient. Similarly, we would look to recover the underspend if the TOs are not able to demonstrate this. We considered three options:

(1) The DPCR5 approach, but focusing on replacement priorities or risk rather than asset health/condition. In DPCR5, we developed a methodology for determining the financial consequences for a DNO which we qualitatively deemed not to have met its output level requirements. The incentive was focused on the 'network

outputs gap' concept, and we applied an incentive rate to the network outputs gap to calculate a revenue adjustment at the next distribution price control.
(2) The DPCR5 approach, amended to become symmetric. This option would introduce a reward for over delivery, which would potentially be symmetric in terms of the sharing rate, and would be subject to a "customer test". A significant advantage of this approach is that a reward would allow companies the flexibility to carry out additional investment to reduce risk if this in the interest of consumers. One drawback of the symmetric approach is that it might incentivise network companies to systematically over deliver, unless the consumer test was very well defined.
(3) Carrying forward the agreed baseline secondary deliverables to the next control period. Under this option, any under delivery or over performance is taken into account. As part of the business planning process for the next price control review, the companies will need to demonstrate that the extra work is justified and is in the interest of consumers.

6.90. On balance, we have decided to pursue option 3 above. Our view is that with this option the "consumer test" is still present, but it becomes part of a structured process (the overall business planning exercise for the following review) rather than on a case by case basis. Under this option, outputs will be carried forward as agreed with any output gap calculated in a similar way to DPCR.

6.91. Until full delivery is reached in the following price control period, the financial difference resulting from the output gap would fall on the TO rather than customers. Although the agreed level of outputs at the end of RIIO-T1 will form the starting point for RIIO-T2, we note that a financial adjustment will be required to allow for the difference in financing costs associated with under or over delivery. We will apply a revenue reduction marginally greater than the financing costs associated with under delivery against agreed levels to ensure that there is not an incentive for the TO to under deliver. Similarly, we will apply a revenue increase marginally less than the financing costs associated with over delivery to ensure companies give careful consideration to the benefits that a higher level of outputs will bring to consumers.

Incentives to optimise constraints costs arising from electricity TO activities

Summary of consultation proposals

6.92. In its role as GB system operator, NG incurs costs when it takes actions to resolve constraints that arise where there is insufficient capacity on the transmission system given the pattern of (scheduled) electricity generation and consumption. These costs are substantial and are, in large part, ultimately passed on to consumers.

6.93. Constraint costs are affected by the availability of the transmission network. This is, in turn, affected by "real time" TO activities, such as taking equipment out of service for maintenance or refurbishment to protect the reliability and health of transmission network assets over the longer term. Constraint costs may be reduced if the duration of these works is shortened or if works are undertaken at times of favourable energy flows (eg when a specific power station that would be behind a constraint is also on maintenance). TOs can also contribute to reducing constraint costs by taking actions that enable increases in circuit ratings either temporarily or permanently, which allow more power to be transferred.

6.94. We sought comment from stakeholders on whether the TOs should be incentivised to optimise constraint costs that result from planned line or substation outages for maintenance or construction works. We put forward an initial proposal that, in principle, constraint costs attributable to a TO's actions should be incentivised in order to minimise total costs to consumers, including constraint costs and the costs that TOs incur. In particular, we identified a case for passing a portion of the SO incentive on to the TOs in Scotland, based on the proportionate level of impact that the TO's activities have on constraint costs. We recognised that there are different ways in which this could be done.

6.95. Over the long term, the constraint costs incurred by NG can be mitigated by investment in additional transmission network capacity or boundary transfer capability. We discuss such investment in Chapter 7 on electricity transmission wider works. The focus here is on actions that a TO can take which affect constraint costs without requiring the installation or upgrade of transmission network assets.

Summary of responses

6.96. Some TOs, a large network user, and a consumer representative group thought it was appropriate that we look further at the options to incentivise constraint costs attributable to TOs actions. One TO did not think it was appropriate to introduce financial incentives to minimise investment related constraints and operational/outage related constraints particularly if potential arrangements expose the TO to a proportion of the SO's outage related constraint costs. They noted that the separate TO and SO roles under BETTA prevent the Scottish TOs from having relevant market information.

6.97. Two respondents thought there should be greater transparency around the location, duration and costs of constraints, the reason there was a constraint and the actions taken to minimise any adverse effect. They wanted to see a reporting mechanism related to actual outages put in place.

6.98. Another TO pointed to several practical issues but did not consider the confidentiality issues relating to Scottish TOs to be insurmountable. They also noted that these issues are currently being reviewed by the Commercial Balancing Services Group.

6.99. One TO noted that incentives on TOs to minimise constraints might compromise the essential asset replacement and refurbishment required to maintain quality of supply. They argued that the incentive should not seek to prioritise constraint minimisation over necessary replacement/refurbishment. They also thought the arrangements should aim to share any constraints savings between SO and TO when there is an opportunity to shorten duration of outages safely.

6.100. A renewable industry group had concerns that an incentive to minimise constraints might undermine the 'Connect and Manage' access regime as this was a relatively easy way to avoid constraints. They thought a broader output measure/incentive scheme to contribute to a low carbon economy would encourage TOs to address the most expensive and common constraints.

6.101. A large network user thought that the alignment of efficiency incentive rate/ sharing factors would provide a better framework for managing constraint costs in England and Wales.

6.102. A consumer group thought it would be difficult to align SO and TO incentives, particularly in relation to electricity transmission. However they thought there was value in further exploring ideas around SO/TO alignment.

Our decision

6.103. Since publishing our December consultation, we have given further thought to the interactions between the TO price controls and the SO incentive schemes, across both gas and electricity transmission. We have also discussed these issues further at the stakeholder working group. We have decided, for the purposes of the business plans due in July 2011, to adopt the following approach.

6.104. We are asking each TO to prepare, as part of its business plan, a network availability policy. The network availability policy will clarify what the SO, and other stakeholders, can expect from the TO insofar as its actions affect the availability of the transmission network. For instance, it should set out how the TO will plan and manage outages and deal with risks of over-runs, including details on working practices. Each TO should explain why its proposed policy is in consumers' interests.

6.105. During the price control period, the network availability policy will be taken as a primary output, within the network reliability and availability category. We will have the ability to impose financial penalties in the event of a TO not complying with its network availability policy. There may also be opportunities for a TO to benefit financially from performance beyond that which is required under its network availability policy, where this is in the interests of consumers.

6.106. We provide further information in the sub-sections below on three elements:

- The output based on a network availability policy
- Penalties for breach of the network availability policy
- Financial rewards for performance beyond network availability policy

6.107. We do not expect to fast-track any TO that fails to provide an effective and comprehensive network availability policy. Non-fast-tracked companies will have an opportunity to refine their proposed network availability policy ahead of re-submission of the business plans in March 2012, in light of our comments and feedback from other stakeholders.

6.108. We recognise that greater alignment between the incentives applied to the TOs' costs and the incentive scheme on NG's SO external costs is important if NG is to operate the system in a way that best balances network costs and constraint costs. We are carrying out separate work on potential changes to the incentive scheme applied to SO external costs. We are considering ways to develop the incentive scheme on NG's SO external costs and to introduce arrangements from April 2013 that are more closely aligned with the TO price control that will apply from April 2013. In particular, we see a case for (1) greater alignment of the sharing factor set for the SO external costs incentive scheme with the efficiency incentive rate to be set under RIIO-T1; and (2) providing longer-term incentives on SO external costs (eg through resets of the baseline or target that are less frequent than each year).

6.109. We believe that an approach based on an agreed network availability policy is more proportionate than one which would directly expose each of the three TOs to a proportion of constraint costs attributed to its transmission network. For such an approach to be effective, this proportion would need to be the same as, or close to, the efficiency incentive rate applied to TO expenditure. Because of the scale of constraint costs, and the uncertainty around forecasts of constraint costs, such an incentive scheme would create substantial additional financial risk in the industry, with potential for large windfall gains and losses.

6.110. We have also identified risks to the effectiveness of an incentive scheme that would expose the Scottish TOs to constraint costs directly. The scope to improve outcomes for consumers by exposing the Scottish TOs to constraint costs is dependent upon these companies understanding likely constraint costs attributable to their networks ahead of time. There are currently limits on what information the SO shares with the TOs (Schedule 3 of the STC sets out the information and data permitted to be disclosed by a party to a TO). We expect that there will remain good reasons to limit the information that the SO makes available about likely constraint costs in advance of settlement periods. There may also be risks that such an incentive scheme could be ineffective in the case where the same corporate group owns both a transmission network company and generation companies that can earn revenue from selling constraint management services to the SO.

6.111. If one or more TO fails to provide an adequate network availability policy, we may need to take a more active role in the development of the policy for that company (eg drawing on the proposals from the other TOs) or to consider alternative options for network availability outputs that do not rely on such a policy.

6.112. If the business plans submitted in July 2011 indicate significant risks that TOs will not develop adequate network availability policies by March 2012, then we will start work to develop alternative options. These options may include incentive schemes under which each of the Scottish TOs would be exposed to a proportion of constraint costs attributed to its transmission network, as well as changes to the incentive scheme on NG's SO external costs.

Network availability policy

6.113. We will ask each TO to include, in its business plan for RIIO-T1, its proposed network availability policy. The TO should explain why the proposed policy is in the interests of consumers, giving particular attention to the potential for the TO's actions to affect network availability, the operation of the transmission system and constraint costs.

6.114. This should include the TO's proposed approach for:

- prioritisation and planning of work (eg how the TO identifies the need for access and makes decisions regarding the placement, duration and flexibility of outages)
- responses to requests to changes to the outage plans agreed with the SO
- managing risks relating to over-runs and delays to outages
- policies on the ratings for transmission network assets that affect the transfer capability of the transmission network
- providing enhanced services over and above the baseline level of service.

6.115. This policy will be additional to any obligations that the TO already faces (eg from the arrangements under the STC code). We expect TOs to identify best practice in relevant areas of transmission network asset management as part of the development of their policies. We are not looking simply for a description of a TO's current behaviour, although comparisons between current behaviour and the proposed policy might be helpful.

6.116. The network availability policy may be a mix of quantitative and qualitative elements. In either case, it will be essential that the policy provides clarity to the SO, and other stakeholders, on what can be expected from the TO and that breaches of the policy can be detected (eg by Ofgem). The policy should not be a set of vague aspirations about achieving benefits to consumers. It should set out concrete things that the TO will do which are expected to be in the interests of consumers. We should be able to monitor whether the TO does these things.

6.117. The base revenue set at RIIO-T1 will be compatible with the network availability policy included as part of the TO's business plan. For instance, we recognise that a policy under which staff are trained and available to work on a 24-hour basis, seven days a week, to minimise the risks of over-runs to planned outages could require greater TO expenditure than an alternative policy which carries a higher risk of over-runs. It would be for the TO to justify the proposed expenditure requirement as in the interests of consumers, taking account of the potential benefits to consumers (eg lower constraint costs).

6.118. As discussed further below, we are also considering ways in which the SO could be encouraged to agree, where appropriate, with the TO for the TO to provide additional services (or better performance) beyond the baseline level of service set out in the network availability policy.

6.119. As part of the development of the network availability policy, each TO should consider potential barriers preventing it from acting in a way that would lead to the best outcomes for consumers (eg a lack of information about constraint costs) and consider different ways of addressing these. We expect that the Scottish TOs will need to develop their policies through discussions with NG SO (eg to explore the potential for information to be shared that indicates the relative value of potential TO actions and decisions).

6.120. The network availability policy will form part of the primary outputs under the category of network reliability and availability.

Penalties for breach of network availability policy

6.121. We envisage that failure to comply with the network availability policy agreed at the price control review would be a breach of the licence which could trigger enforcement action, including a financial penalty.

6.122. Any penalty would be determined in accordance with a set of guidelines and criteria, which we will need to develop further. We set out preliminary information on this below.

6.123. The scale of any penalty that we impose for non-compliance will reflect the potential harm to consumers. In assessing this harm, we will give particular attention to potential for non-compliance to lead to higher constraint costs. This could include analysis of the additional constraint costs that can be reasonably attributed to the specific breach of the network availability policy.

6.124. We will also take account of the need to ensure that a sufficient deterrent against non-compliance exists. As part of this, we will recognise the potential for a TO to reduce its own costs through non-compliance. We will also recognise the potential, in the case of any corporate groups that have both TO and generation interests, for non-compliance to increase the profits from generation activities (eg it is possible that an outage of excessive duration on part of a transmission network may increase the revenues that some generators earn from offering constraint management services to the SO).

6.125. We recognise that the Scottish TOs do not have the same information as NG on the likely impact of their actions on constraint costs. The Scottish TOs will need to work with NG SO to develop a network availability policy that can be complied with given the information available and to resolve information deficiencies where possible. We will need to ensure that any penalties imposed for non-compliance are reasonable in light of the information that would have been available to the TO at the time it took decisions that led to non-compliance. For instance, if constraint costs at a particular network location at a particular time of year were exceptionally high compared to historical levels and any published forecasts, and there was no way for a Scottish TO to anticipate this, it may not be appropriate to expose a Scottish TO to a penalty that matches the actual constraint costs attributed to non-compliance.

6.126. Any decision we make in respect of potential penalties for non-compliance will take account of the extent to which a TO may already have suffered financial consequences as a result of non-compliance. This is particularly relevant in the case of NG, because of NG's exposure to constraint costs through its role as SO. We now discuss this in more detail.

6.127. We highlighted above that we are considering potential changes to the SO external costs incentive scheme, which may lead to greater alignment of the sharing factor under the SO scheme with the efficiency incentive rate applied to the TO. This may limit the need for any penalty for non-compliance to be applied to NG through the price control arrangements. It remains important to have the option to impose such penalties as part of the arrangements for the TO price control. This is because, at this stage, it is possible that NG's exposure to the constraint costs arising from non-compliance may be more limited than consumers' exposure to these costs (eg if any cap is applied to the incentive scheme on SO external costs).

6.128. NG should consider these interactions when it develops its network availability policy as part of its business plan.

Financial rewards for performance beyond network availability policy

6.129. During the price control period, there are likely to be opportunities for a TO to do things that go beyond the minimum requirements of the network availability policy and which are in the interest of consumers. Opportunities may arise from a number of different sources, such as:

- innovations to asset management practices during the price control period
- changes over time in the costs that a TO faces.

6.130. We see potential benefits in arrangements that would provide TOs with financial rewards to take opportunities to go beyond the minimum requirements of the network availability policy where this is in the interests of consumers. This would involve coordination between the SO and TOs, such as through:

- SO requests to the TO for voluntary improvements in its service, based on the SO's understanding of the latest information on the scale, location and timing of constraint costs.
- The TO offering enhanced services to the SO, which the SO could choose to take up, again based on the SO's understanding of constraint costs. These enhanced services could either be included, as options, in the network availability policy or developed and agreed during the price control period.

6.131. Since our December document, we have given more thought to the potential for greater alignment between the incentive scheme for NG's external SO costs and the TO price controls and to the interactions between NG, as SO, and the Scottish TOs. We have identified ways in which changes to the SO incentive schemes could provide the basis for TOs to earn rewards for going beyond the minimum requirements of their network availability policies, where this is in the interests of consumers.

6.132. The source of any financial rewards would be from the SO and the SO incentive scheme. The nature of any financial rewards would differ, in some respects, between NG and the Scottish TOs. This is because NG is directly exposed to variations in constraint costs in its SO role, while the Scottish TOs are not.

6.133. In the case of NG, greater alignment between the sharing factor applied to SO external costs and the efficiency incentive rate applied to TO costs could provide financial incentives for NG to consider ways in which actions which affect its TO expenditure could help reduce constraint costs. For example, NG may identify a new approach to managing outages on the England and Wales transmission network that goes beyond that which is required under its network availability policy. If the reductions in constraint costs from the new approach exceed the additional TO costs incurred under that approach (if any), then NG could benefit financially from adopting it. The reductions in costs across the SO and TO taken together would, in turn, benefit consumers.

6.134. We also see benefits in an approach under which NG, in its role as SO, could make payments to the Scottish TOs as part of agreements to do things which can reduce constraint costs and which go behind the minimum requirements of their network availability policies. This would provide a way in which the Scottish TOs could earn revenues from going beyond the minimum requirements of their network availability policies in cases where this is in the interests of consumers (eg in cases where the TO would incur additional costs but these costs are outweighed by the benefits to consumers from lower constraint costs). NG, in its role as SO, would be responsible for deciding whether to seek such agreements, taking account of the potential for such agreements to reduce the constraint costs that it incurs.

6.135. We recognise that there are currently arrangements in place through the STC to allow NG to request changes to the agreed Final Outage Plan (FOP) and to allow the Scottish TOs to recover reasonably incurred costs from the SO. The approach identified above differs from this in a number of ways, including the potential for a TO to earn a financial benefit beyond cost recovery and opportunities for payments from the SO to TOs for a wider range of actions that could help reduce the costs borne by the SO. A proportion of any of the revenues that a Scottish TO receives through these arrangements would be passed through to consumers through reductions to the allowed revenues under the price control. This proportion would be determined by the efficiency incentive rate applied to the Scottish TO (eg if the efficiency incentive rate is 40%, then a company receiving a payment of £100 would retain £40 before tax). This is necessary to avoid perverse incentives, given that a large proportion of each TO's actual expenditure will be passed on to consumers under the efficiency incentive rate.

6.136. Any payments made by NG, in its role as SO, to the Scottish TOs would be treated as SO external costs and would affect Balancing Service Use of System (BSUoS) charges.

6.137. In the case of NG, the SO and TO activities are carried out by the same company. Where NG does go beyond the minimum requirements of its network availability policy in order to reduce SO external costs, it may be appropriate to allow for any additional TO costs that arise to be reclassified and treated as SO costs for regulatory purposes. For example, different charging methods are used to recover the TO allowed revenue and the SO external costs and it is possible that such a reclassification would allow for a fairer allocation of such additional TO costs across network users.

6.138. We will continue to progress our thinking around the alignment of the incentives on the SO and TO. We expect to publish our initial thoughts on potential mechanisms for identifying and rewarding opportunities for TOs to provide enhanced services, that go beyond the minimum requirements of their network availability policies, in early June.

7. Secondary deliverables - electricity transmission wider works

Chapter Summary
This chapter sets out our approach to setting secondary deliverables for companies for electricity transmission wider reinforcement works. It confirms how we intend to specify and provide revenue allowances for increases in boundary capability. And it sets out the flexibility mechanisms to help manage uncertainties around the scale, timing and funding of critical infrastructure investments over RIIO-T1. We also explain our decision in relation to financial incentives for timely delivery.

7.1. We are committed to encouraging network companies to play a full role in a sustainable energy sector and tackling climate change. In 2009, the Transmission Study (ENSG Report), a joint industry initiative, identified that a large number of major transmission reinforcements would be needed to meet the Government's 2020 targets. We introduced Transmission Investment Incentives (TII) in 2009 to supplement capital allowances and deep revenue arrangements set within TPCR4 to facilitate the timely delivery of critical electricity transmission infrastructure projects. We have extended these arrangements for the rollover year 2012-13.

7.2. In RIIO-T1 we are putting in place enduring funding arrangements to ensure that network companies are able to undertake timely investment in electricity transmission capacity to accommodate new generation when it connects. As we have indicated before these funding arrangements will supersede TII and the deep revenue drivers for electricity transmission in the current price control (TPCR4) from 2013-14. Chapter 8 sets out our thinking for meeting wider system flexibility on the gas transmission network.

7.3. We intend to specify secondary deliverables for electricity transmission wider works in terms of increases in boundary capability in accordance with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). We are working with TOs to define increases of boundary transfer capability that are practical and workable in the RIIO outputs framework.

7.4. We expect that most of the companies' wider works investment will be funded through base revenue. TOs will need to put forward levels of boundary capability that are consistent with their forecast baseline expenditure in their business plans. They will also need to provide information on how the required investment schemes and associated levels of expenditure might change with variations in transfer capability at boundaries that drive network investment.

7.5. Changes in generation connections can affect the need for network reinforcement. To fulfil their duty to develop and maintain an efficient and coordinated system of electricity transmission we expect TOs to be forward looking and alert to developments and adjust their plans in the interests of consumers. TOs will incur costs in undertaking this duty. We expect TOs to set out revenue allowances in their business plans and justify the scope and scale of work this will cover. We expect this will include maintaining a strategic network development plan, ongoing assessment of the needs case for potential reinforcements as well as pre-construction costs to ensure timely and efficient delivery.

7.6. We are including three flexibility mechanisms in RIIO-T1 to vary the size, timing and revenue allowances for boundary capability relative to TOs' baselines. We have designed the set of mechanisms to manage the uncertainties around strategic network reinforcements, difficulties of forecasting expenditure requirements and to avoid micro-management.

7.7. Two of these mechanisms will automatically adjust TOs' allowances for variations in load related investment relative to the baseline forecast. The first will release an allowance, subject to a pre-specified trigger event, for increasing capacity at a particular boundary based on total costs agreed at the price control settlement. The second mechanism will adjust baseline allowances for changes in boundary capability through a volume driver calibrated at the price control on forecast unit costs. We expect that these arrangements, in combination with the baseline revenue, will fund most companies' wider works investment programmes.

7.8. We will also operate streamlined arrangements to determine costs within RIIO-T1 for a limited number of wider works investments. This mechanism will only be available for secondary deliverables which would otherwise present substantial risks for consumers or the individual companies if taken forward under one of the other funding options.

7.9. Under some of the arrangements we will be able to agree a target delivery date. To ensure timely delivery we will impose a financial penalty in the event of late delivery.

7.10. In addition to giving more information on the above arrangements and our rationale for them, this chapter summarises the issues stakeholders raised in response to the December document and our further thinking on these.

Summary of consultation proposals

7.11. In the December document we proposed setting a secondary deliverable on TOs for wider reinforcement works to connect new low carbon generation where it is in the interests of consumers. We proposed to specify this secondary deliverable in terms of increases in boundary transfer capability rather than specific projects as is the case under TII.

7.12. We also consulted on a set of flexibility mechanisms to vary companies' funding allowances for delivering variations in boundary capability relative to baseline. We proposed a mix of these would replace TII, the temporary funding arrangements introduced following the Transmission Access Review,[28] as well as the deep revenue drivers in TPCR4.

7.13. We consulted on four flexibility mechanisms. These were:

- Option (a): Potential trigger mechanisms through which the required capacity and associated revenue allowance would adjust mechanistically during the price control period according to pre-specified criteria.
- Option (b): Provisions to allow us to make within-period determinations to approve additional increases in boundary capability, and to provide associated upfront funding during the price control period. This would have similarities to the TII mechanism.
- Option (c): Provisions under which the TO would have flexibility to choose what level of increase in boundary capability to deliver (up to an agreed maximum). This would be subject to the investment being compatible with the company's network planning policy that we have to approve. Funding for the increases in boundary capability would be provided through a volume driver calibrated at the price control review in light of forecasts of the unit costs of increases in capacity.
- Option (d): An upfront utilisation incentive scheme such that a TO would be able to choose what increase in capability to develop at a specific transmission boundary and would bear financial risks (penalties and rewards) related to subsequent boundary transfers at that boundary.

7.14. We proposed that a combination of (a), (b) and (c) could bring benefits to consumers.

7.15. We said that we would seek to develop arrangements under which TOs would have appropriate financial incentives around the timeliness of delivery of increases in boundary capability, which reflect the impacts of later delivery on consumers (constraint management costs or another measure of the harm from late delivery).

7.16. We invited views on how to encourage the timely delivery of agreed secondary deliverables, taking account of interactions with the primary outputs for network reliability and availability and the role of the SO. We set out our thinking on how to treat non-delivery within the price control period that was/was not in the interests of consumers. We also discussed issues around wider works that span more than one price control.

Summary of responses

7.17. Some stakeholders did not agree with the terminology of secondary deliverables on TOs in relation to wider reinforcement works. These stakeholders said that the proposal sent a message that wider reinforcements are a 'secondary' priority. Some stakeholders said that they would prefer wider reinforcements to be a primary output for TOs to deliver against. They thought a secondary deliverable was

[28] The Transmission Access Review considered arrangements for access to the GB transmission system with the chief aim being to better support the delivery of 20 percent of electricity supplied by renewable generation by 2020.

counter intuitive when key reinforcement works are the main investment driver for companies over RIIO-T1 and an imperative for the UK's low carbon targets.

7.18. Network companies were divided on the substance of the consultation proposals. One company does not agree with setting the wider reinforcement works secondary deliverable in terms of boundary capability or moving away from current funding arrangements for specific projects provided by TII. Their main concern is that large load related investments are not suited to fixed financial allowances – whether ex ante or mechanistically fixed to pre-defined outputs. They argued that using such an approach could delay vital upgrades, create perverse incentives in timing or which reinforcement to deliver, and stifle innovation. Another company also had a preference to retain the status quo and welcomed the proposal to include a within-period type arrangement as one of the flexibility mechanisms. One company supported the proposals.

7.19. Feedback from other stakeholders on this area was limited. One large user thought it was important that investment plans underwent robust and rigorous scrutiny given the potential scale of these investments and the impact they can have on consumer charges. This stakeholder thought there was too much uncertainty associated with these investments to take a view at the time of the price control settlement on costs of delivery or unit costs.

7.20. The TOs have noted that there will be some complexity around setting the secondary deliverable in terms of boundary capability. This is because transfer capability at a given boundary can change as a result of variation in the background demand and generation profiles and with changes in neighbouring transmission zones.

7.21. There was clear agreement across stakeholders of the need to include a variety of flexibility mechanisms to help manage uncertainties around costs, timing and scale of critical infrastructure investments. Stakeholders particularly welcomed the continuation of a mechanism for within-period cost determination closer to the point when TOs undertake construction, particularly for those reinforcements that are large scale.

7.22. One TO agreed with the proposal to link financial incentives related to delays in delivery with constraint management costs. They also thought that this would be helped by greater consistency between the SO and TO incentives.

7.23. One TO said that it took delivery of all investment, and particularly those associated with wider reinforcements, very seriously. They identified that "there is a business driver in increasing the regulatory asset value (RAV) as quickly as possible" and also a reputational driver given the link between network reinforcements and Government energy policy. They also raised concerns over incentives that cover the full period of delivery of a project if this includes planning consents and thought there should be exclusion provisions related to local authority or Government consent delays and land owner delays.

7.24. One respondent thought it would be unfair to claw back the full avoided costs when non-delivery is in consumers' interests. They thought that the efficiency incentive rate should apply to any underspend so that consumers and the company shared any underspend. They did note that careful design would be needed to avoid unnecessary projects in plans.

Our decision

Specification of wider works

7.25. Some stakeholders stated a preference for wider works to be classified as a primary output. We reiterate our view that the terminology secondary deliverable should not be taken to mean that the delivery of critical infrastructure is less important than the delivery of primary outputs. In the RIIO handbook we set out how we would apply secondary deliverables. We explained that this would be necessary in areas where TOs' asset management or forward planning practices have a significant impact on their ability to deliver primary outputs in future periods. We also thought it would be important to set specific secondary deliverables on TOs in areas where there is a time lapse between the point at which the TO incurs the expenditure and when the contribution from that expenditure will be realised in primary output measures.

7.26. Wider reinforcement works in electricity transmission are absolutely critical for the long-term delivery of network reliability and availability, as well as the achievement of UK's low carbon energy goals. We recognise that boundary capability is itself a measure of long-term availability of the transmission network and therefore could be a primary output. However we consider the most important issue is the substance of the arrangements and that they facilitate the required investment. At this stage we do not consider it necessary to reclassify wider works as a primary output.

7.27. We intend to proceed with our consultation proposal to specify for each TO wider works in terms of increases in boundary transfer capability where practical. We believe this approach is consistent with the output performance framework of RIIO and is preferable for three reasons: (1) the impact of an increase at a given boundary capability on network services valued by customers and users is more transparent than a specific project, ie to address a system weakness to accommodate more generation or demand in a given zone, (2) specifying in terms of boundary capability rather than a specific project will allow TOs greater flexibility to innovate over a longer term price control in the way they meet secondary deliverables, and (3) it provides stronger efficiency incentives to TOs as they have a greater choice over the appropriate and more efficient solutions than they would if specified in terms of a particular project.

7.28. We have discussed with TOs the practicalities of using boundary transfer capability as a secondary deliverable for wider works. We are currently working with TOs to develop a pragmatic approach to setting secondary deliverables in terms of boundary capability, consistent across companies and with the NETS SQSS methodology. This will also consider the treatment of major reinforcements that might, for example, cross several boundaries or are to be undertaken on part of the network where there is currently not an existing boundary. The onus will be on the TOs to identify and define new boundaries where they are important drivers of investment during RIIO-T1.

7.29. We are also considering how we will assess TOs' delivery performance in terms of increased transfer capability at a particular boundary over the price control. Boundary transfer capability, as a measure, is dependent on several contributing factors including the operation standards and the generation and demand background at a particular point in time. It is therefore important we take into account any significant variations in the background factors from those assumed in the baseline as well as the potential impact on the measured boundary capability TOs subsequently deliver.

7.30. We want to minimise any ex ante forecast error as this could, for example, lead to consumers paying more than is necessary or companies delaying wider works if revenue allowances are insufficient. At the same time we want to limit the ongoing administrative burden during the price control. One way to manage this would be to have a view as to the degree and types of uncertainties that relate to increases in capability at a particular boundary.

7.31. To help inform our view, as part of their July business plans, we are requiring companies to provide a baseline as well as upper- and lower-bound forecasts for investment in wider works during RIIO-T1 and associated boundary capability. These upper and lower bounds should be based on representative scenarios that capture the likely maximum and minimum investment scenarios for the system as a whole taking account of what could reasonably occur across the range of boundaries in combination. In addition, companies are required to specify upfront as part of their plans a baseline as well as the upper and lower bound of anticipated changes in transfer capability at a given boundary. This information will form part of a well-justified needs case and will indicate the degree of confidence around the anticipated increase at a boundary. If boundaries are identified through this process as having particularly high sensitivity to changes in background assumptions we can consider how to mitigate the potential risks through providing extra flexibility, eg different unit cost allowances for different tranches of boundary capability increases, or potentially a minimum increase in boundary capability agreed as a baseline.

Funding arrangements for wider reinforcement works within RIIO-T1

7.32. The funding framework we intend to implement as part of RIIO-T1 will ensure TOs are able to undertake timely and cost effective investment to meet demand for additional capacity, in the long term interest of consumers.

General principles for funding secondary deliverables in RIIO-T1

7.33. Companies are required to propose and justify secondary deliverables related to wider works and network reinforcement in the interests of existing and future consumers. A well-justified business plan will include a stakeholder tested needs case covering the following information on proposed boundary capacity increases:

- **Context**: This should set out the background against which expenditure on boundary capability would be needed. It should include reference to connected, contracted and prospective generation as well as different future scenarios and alternative ways in which desired outcomes could be delivered. The TOs should set out how they have considered alternative scenarios and incorporate the latest available information to form an appropriate view of the baseline scenario for their business plans.
- **Stakeholder engagement**: The TOs should demonstrate that they have engaged with a range of stakeholders in relation to their proposed approach, including consumers, generators, local authorities, the SO and other TOs.
- **Impacts – benefits**: The TOs should include an overview of the benefits that they and stakeholders consider could be achieved as a result of their proposed approach. Benefits should be referenced in terms of their impact in a number of areas, including low carbon flows on the networks to help meet the 2020 renewable energy target and longer term decarbonisation goals, losses, wider sustainable development factors, reliability and the economic and efficient operation of the system, including lower constraint costs. If TOs think benefits could arise in other areas they should seek to include reference to these.
- **Impacts – costs**: TOs should set out their views in terms of the costs that they would be likely to incur in implementing their proposed approach. This should be presented in terms of costs of required reinforcement and costs resulting from the associated network outages that would need to take place. If TOs consider that costs could arise in other areas they should also include reference to these.
- **Risks and uncertainties**: The TOs should include lower- and upper-bound scenarios around the baseline proposals set out in their business plans both in terms of the system as a whole and for individual boundaries. In addition, they should identify where uncertainties exist and provide details of the uncertainty mechanisms they think are required to mitigate these unknown factors.
- **Other requirements**: TOs should also show that they have had regard to the potential links that this secondary deliverable has with other primary outputs and considered mechanisms that could be utilised to avoid double counting.

7.34. We will decide on whether to accept a TO's proposals set out in its business plan. On the basis of our decision, we would include in the TO's price control settlement an efficient level of forecast costs associated with secondary deliverables that have been appropriately justified.

7.35. TOs will need to include details of the proposed and alternative projects to establish the costs of delivering sustainable and good value increases in boundary capability. TOs will not be held to the delivery of the specific project or be subject to an ex post efficiency review as long as the agreed secondary deliverable was met.

7.36. The above principles will also apply to other arrangements such as trigger events and volume drivers to vary boundary capability deliverables and revenue allowances, beyond those agreed at the price control review.

Interactions with existing funding arrangements

7.37. As part of TPCR4 we introduced an uncertainty mechanism to allow NGET’s capex allowance to flex in response to changing patterns of generation and demand.

This flex was intended to account for differences between the boundary reinforcements assumed at the start of the price control (and incorporated into the base capex allowance) and reinforcements that are actually required in response to signals from generation and demand customers.

7.38. By the end of TPCR4 rollover, NGET will have undertaken a number of projects for boundary reinforcement under the revenue drivers. We will reflect these works when we set the baseline revenue allowance and baseline boundary capacity for RIIO-T1.

7.39. In 2009 we introduced TII to provide interim funding arrangements within TPCR4 for companies to proceed with critical infrastructure works identified by ESNG. In total thus far, 18 projects have started since 2009, for which we have agreed a total of about £400 million in capital allowances for pre-construction and construction works up to the end of 2012-13.

7.40. Projects initiated under TII and in progress at the end of TPCR4 rollover will be integrated into the RIIO-T1 baseline funding arrangements and secondary deliverables from 2013-14 onwards.

7.41. TOs will need to provide information on these projects in their RIIO-T1 business plans. This should set out the progress made on deliverables linked to funding provided under TII and where it is practical translating the baseline underpinning the project into a secondary deliverable related to boundary capability. Where there are significant changes from the forecasts originally provided as part of the TII applications the TOs will need to provide appropriate justification for the changes.

Baseline funding

7.42. We require companies to submit proposals in their well-justified business plans for secondary deliverables related to increases in boundary capability. The ENSG report will be an important input but should not supplant TOs' more detailed forward planning, including stakeholder engagement on the needs case for increases in boundary capability. TOs will need to give appropriate consideration to the range of scenarios that might arise and provide a robust explanation of how they have chosen their baseline scenarios taking into account both stakeholders' views and the best available information on what is happening on their networks.

7.43. Drawing on a review of the TOs' business plans, we will include secondary deliverables defined in terms of increases in transfer capability, that are in consumers' interests, across specified transmission network boundaries, as part of the price control. For those secondary deliverables agreed at the price control review, we will apply the funding principles set out above and include forecasts of the expected (efficient) costs of delivering them as an input to setting base revenue.

7.44. Changes in generation connections can affect the need for network reinforcement. To fulfil their duty to develop and maintain an efficient and coordinated system of electricity transmission we expect TOs to be forward looking and alert to developments and adjust their plans in the interests of consumers. TOs will incur costs in undertaking this duty. We expect TOs to set out revenue allowances in their business plans and to justify the scope and scale of work this will cover. This could include allowances to maintain a strategic network development plan, ongoing assessment of the needs case for potential reinforcements as well as pre-construction costs to ensure timely and efficient delivery.

Flexibility mechanisms for RIIO-T1

7.45. Any view of required increases in boundary transfer capability at the start of the price control, will be subject to uncertainties around the exact timing, scale and costs of the network reinforcements needed.

7.46. We intend to provide extra flexibility over RIIO-T1 to adjust the secondary deliverables that are in consumers' long-term interest. We intend to supplement baseline funding of TOs for secondary deliverables with two of the mechanisms set out in the December document to automatically adjust funding through (1) a trigger event funding contingency, and (2) boundary specific volume drivers. In addition we intend to implement the third proposal for a streamlined within-period cost approval process for a small number of secondary deliverables that are needed over RIIO-T1.

7.47. We set out below more information about the different flexibility mechanisms so that companies can consider how they might use these options in relation to the potential reinforcements required on their networks. We expect companies to set out in their business plans their preferred options and justification for why this will provide the appropriate level of flexibility for managing uncertainties around their network wider works and why this is in the best interests of consumers. We expect most of the companies' wider works expenditure will be funded through base revenues and the automatic flexibility mechanisms.

Trigger mechanism calibrated at the price control

7.48. At the price control review, a TO may identify that the needs case for a potential increase in boundary capability depends on certain things happening over the price control period. In these circumstances, it may not be in consumers' interests to commit to that increase in boundary capability at the price control review. Instead, the requirement for the increase in boundary capability could be made contingent on a 'trigger' event if a clear justification for the increase in boundary capability would arise from that event happening. The nature of any trigger event would be case specific, but could, for example, relate to:

- planning permission granted for a set of potential generation projects
- transfer capability at the transmission boundary reaching a specified level.

7.49. Under this option, we will estimate the costs of the increase in boundary capability at the price control review and if the trigger event occurs, the TO's allowed revenue for the remaining years of the price control, and subsequently its regulatory asset value, would adjust to reflect this. The revenue adjustment would be automatic, based on a specification set at the price control period. It would not require significant administrative work during the price control period.

7.50. We expect companies to set out, as part of their business plans, whether this mechanism is appropriate for potential network reinforcement work they have identified. Appropriate circumstances would include a clear link between the trigger event and the need for the increase in boundary capability, and the ability to make a reasonable estimate of the costs of that increase at the price control review.

Network planning policy and volume driver agreed upfront

7.51. An alternative way to provide flexibility is for TOs to be given some discretion as to the level of capability at a given boundary, subject to it delivering a minimum increase agreed at the time of the price control. There will be safeguards to ensure that the TO takes reasonable decisions in the interests of consumers about what to deliver. The variation in boundary capability relative to the baseline will be remunerated on cost estimates made at the price control review. This mechanism will also be used to adjust baseline allowances if increments in boundary capability over the agreed minimum anticipated at the time of the price control and funded in baseline revenues turn out not to be needed.

7.52. We intend to make this option available to TOs. It would operate with the following elements as consulted in December:

- At the price control, the TO will need to prepare a network planning policy that it will use to decide whether to deliver different levels of boundary capability to that agreed at the price control review. TOs will need to explain in their planning policy how they intend to assess and demonstrate the needs case. We expect a big part of TOs planning policy will involve stakeholder testing, including with the SO, the needs case for a particular reinforcement rather than waiting for the next price control period for us to assess whether it is necessary to commit consumer funding to the project. Similarly, the company will also need to explain its decision to deliver a lower level of boundary capability and why this was in consumers' interest.
- At the time of the price control we would have to approve that the network planning policy is in consumers' interests. There will be transparency regarding the approval process for a network planning policy.
- We will determine a unit cost allowance based on forecasts to apply for increases or decreases in boundary capability that the company chooses to deliver relative to what was agreed at the price control review. We expect we will need to set different unit cost allowances for different transmission network boundaries.
- The company will take decisions, during the price control period, on potential increases or reductions in boundary capability compared to the level agreed at the price control review based on up-to-date information.

- We will monitor the company's compliance with its policy agreed at the price control review. If we found that the company had taken decisions that were not reasonably compliant with its policy, whether through action or inaction, we will take action to protect consumers. In particular, we could impose a financial penalty reflecting an estimate of the harm to consumers. This harm could come through consumers' exposure to the costs of funding projects that were not needed or potentially the constraint costs from failure to proceed with an investment project that the policy would require.
- We will decide, at the price control review, a minimum increase in capability for a given boundary that is in consumers' interest and this will lie outside the scope of the volume driver. We will also decide thresholds around this for the maximum increase or decrease in boundary capability that could be reflected through this mechanism (for each boundary).
- For large increases in boundary capability, with substantial cost implications for consumers, it may not be appropriate to rely on this mechanism to ensure increases in boundary capacity are limited to those that are in consumers' interests, and it may be better for us to review and approve these directly—either at the next price control review or within the price control period using the arrangements described below.

Within-period cost determination

7.53. We intend to introduce a streamlined within-period mechanism to provide additional revenue allowance to all three TOs. This will fund efficient forecast costs for a limited number of secondary deliverables identified on the basis of substantial materiality, needs case and TO readiness. Funding under this arrangement will be provided ex ante for the efficient costs of TOs meeting an agreed secondary deliverable in relation to boundary capability.

7.54. Within-period determinations during RIIO-T1 will be limited to funding efficient forecast construction costs only. Pre-construction costs (including planning, design, and the preparation of planning applications) will not be provided through this mechanism. We expect TOs to submit proposals as part of their well-justified business plans for expenditure in their baseline funding to cover pre-construction costs as necessary business costs of carrying out their network planning duties.

7.55. To streamline the within-period arrangements we intend to implement a two stage process. In the first stage a TO would need to demonstrate to us that (1) the proposed deliverable is substantially material to warrant closer regulatory scrutiny, and (2) that there is reasonable certainty of need. Only after the materiality and needs case is established will a company be able to submit the proposal into the second stage process for further detailed assessment of the funding requirements. We will allow companies to submit proposals to the first stage process at any time.

7.56. Companies will need to justify clearly why a proposed secondary deliverable is substantially material to warrant closer regulatory scrutiny. Potential considerations might include a combination of uncertainties and risks around the costs, scale, timing, planning issues or technology associated with a particular wider works investment. These issues could also be compounded if a company has limited scope to diversify its risks through its investment portfolio. Additionally, for some companies, large scale investments might also pose particular challenges given the relative size of their current asset base.

7.57. Companies would need to present the needs case for the proposed works and also justify the reasonableness of the scope and the proposed timing. The stakeholder tested needs case should include the same information as described above under the general funding principles for RIIO-T1.

7.58. Some major projects have encountered significant delays at the planning stage which have delayed the realisation of the anticipated benefits, such as the connection of low carbon generators. We would expect the TOs to include in their timelines realistic estimates of the time that is likely to be required to address the concerns of stakeholders and to complete the planning process. In particular, we would expect the TOs to demonstrate how they are applying the lessons that have been learned from the planning process for previous projects.

7.59. TOs should provide stakeholder views as part of their first stage submission.

7.60. When a TO's proposal has passed the first stage they can proceed with submitting further information to the second stage for detailed consideration and scrutiny of the expenditure requirements. We will require the TOs to present comprehensive and detailed costs of proposed plans and also to justify the proposed works against technical readiness and cost effectiveness. This justification would have to include assurances that any necessary pre-construction work had been completed, or that it was on schedule to allow construction work to commence at a specified time in the future.

7.61. We would provide the TOs with guidance for the format and content of the submission, and would provide a template for the submission of key parameters. We would expect a high standard of submissions, and would reserve the right to impose penalties if submissions transpired to be inaccurate or incomplete. Due to the potential efficiencies and synergies from considering several proposals at the same time we think it is appropriate that our assessment of proposals takes place only at certain agreed times, for example, every 12 months. We would commit to providing a decision within an agreed length of time.

7.62. In the second stage we will assess the companies' forecasts of total construction costs to complete the secondary deliverable by the scheduled completion date. Companies' submissions would have to detail the total costs to be recovered over the entire duration of the works, as well as the profile of these costs year on year. We would reach a decision on what we considered to be the reasonable costs that the TOs should recover, as well as the cost profile. Once the costs had been agreed, we will not review the costs allowances again, unless exceptional circumstances arose.

7.63. Once the efficient cost allowance had been set and agreed, the funding mechanism would be used to allow the TOs to recover the profiled expenditure. In general, at the start of the construction work, we would commit to funding for the entire duration of the works. An exception could be any works whose later years were expected to fall within the next price control period. In such cases, we might commit to funding only up to that juncture, in order to avoid complicating funding decisions taken under the next price control.

7.64. The application of the efficiency incentive will expose the TOs to a proportion of overspend, and would share any under spend with consumers. The costs recovered by the TOs will be adjusted for inflation. As is the case with baseline capex, a fixed proportion of the capital additions arising from the within-period determinations during RIIO-T1 would be entered into the main RAV in line with the profiled expenditure. This would earn the same rate of return as the rest of the regulatory asset value under RIIO-T1. The remainder of the costs would be expensed.

7.65. It will be necessary to assess the TOs' performance against the agreed secondary deliverables, completing whatever works were appropriate. As TOs will submit proposals for within-period determinations close to the point of actual construction we expect these to relate to specific assets. It should be relatively straightforward for companies to measure a specific project in terms of increases in boundary capacity when the funding allowance is agreed.

7.66. TOs will be required to provide us with annual reports on additional capital expenditure through the annual regulatory reporting process. We do not think that it will be necessary to use the same level of monitoring and reporting that is required under the existing TII process.

7.67. A TO's performance against agreed secondary deliverables will be assessed by the timeliness in delivering the agreed increase in boundary capability. We recognise that owing to the large scale of these works and the likelihood that other network reinforcement is also being undertaken on different parts of the network at the same time that we will need to account for potential interactions. For example, if one set of works was dependent upon another reaching a certain stage by a certain time, then it might be appropriate to take into account the knock on effect of a delay in completing reinforcements elsewhere on the timing of a secondary deliverable.

7.68. We will work with stakeholders to finalise these arrangements.

Arrangements to encourage timely delivery – financial incentives

7.69. We expect the base revenue set at the price control review to include funding for work to increase transfer capability at transmission network boundaries, and we will agree a target delivery date for the associated secondary deliverables.

7.70. There would also be a target delivery date for any secondary deliverables for wider works that are agreed through within-period determinations or which arise as the result of a trigger mechanism agreed at the price control review.

7.71. In contrast, no target delivery date would apply in cases where wider works are carried out as part of arrangements based around a volume driver mechanism. In these cases, the TO would have discretion on the precise timing of delivery subject to the network planning policy agreed at the price control review.

7.72. In cases where a target delivery date does apply, we have decided that we will address late delivery through the imposition of a financial penalty. The level or application of any penalty will be at our discretion. We do not consider that the timeliness of delivery of reinforcement of the transmission system is well suited to a fixed ex ante incentive rate.

7.73. We recognise the importance that network companies may attach to the timely delivery of investment and that there are possible financial and reputational motivations to deliver on time. However, we cannot be sure that these will be enough to prevent the risk of late delivery that could expose consumers to substantial additional costs. The existence of these motivations does not detract from the need for financial penalties for late delivery.

7.74. We will not introduce a specific incentive mechanism to reward TOs for early delivery of these secondary deliverables. We explain below how other elements of the regulatory regime may provide financial rewards for earlier delivery where this is in the interests of consumers. Our decision recognises that greater alignment between the TO price controls and the incentive scheme applied to SO external costs is necessary for an effective set of arrangements.

Penalties for late delivery

7.75. In terms of the scope for financial penalties related to delays to delivery, we agree that there is a potential case for exclusions for delays relating to planning consents or land acquisition that are outside the reasonable control of TOs. There are related questions about whether the target delivery date to which penalties for late delivery apply should be set before or after planning consents have been obtained.

7.76. It will be for companies to propose an approach in their business plans. We do not believe that delays related to planning consents are entirely outside the control of a TO. For instance, aspects of the planning and design of a project will affect the likelihood of delays relating to planning consents. We can see merits in an approach in which a TO does face some financial risk around planning consents, as this may provide financial rewards to encourage innovation and best practice in the planning and design of projects.

7.77. Any penalty imposed for late delivery would be determined in accordance with a set of transparent guidelines or criteria, which we will need to develop. We set out preliminary information on this below.

7.78. The scale of any penalty that we may impose for late delivery will reflect the potential harm to consumers. In assessing this harm, we will give particular attention to the additional constraint costs that can be attributed to the late delivery. We may also take account of other sources of harm (eg if systematic late delivery were to prevent the achievement of the 2020 targets).

7.79. Any decision we make in respect of potential penalties for late delivery will take account of the extent to which a TO may already have suffered financial consequences due to the late delivery. This is particularly relevant in the case of NG, because of NG's role as SO and its exposure to constraint costs. We discuss this below.

7.80. We are considering ways to develop the incentive scheme on NG's SO external costs and to introduce arrangements from April 2013 that are more closely aligned with the TO price control that will apply from April 2013. In particular, we see a case for (1) aligning, as far as possible, the sharing factor set for the SO external costs incentive scheme with the efficiency incentive rate to be set under RIIO-T1; and (2) providing longer-term incentives on SO external costs (eg through resets of the baseline or target that are less frequent than each year). We expect to publish our initial thoughts in early June.

7.81. NG would bear, through the SO external costs incentive scheme, financial consequences from late delivery of agreed increases in transmission network boundary capability to the extent that this gives rise to additional constraint costs.

7.82. Whilst this may limit the need for any penalty for late delivery to be applied to NG through the TO price control arrangements, it remains important to have the option to impose such penalties. This is for two reasons:

- NG's exposure to the constraint costs arising from late delivery may be more limited than consumers' exposure to constraint costs from late delivery (eg if any cap is applied to the incentive scheme on SO external costs or if the incentive scheme remains short-term).
- The harm to consumers from late delivery may arise from factors other than late additional constraint costs.

Potential for rewards for early delivery

7.83. We do not envisage an additional incentive scheme under the TO price controls that would provide direct financial rewards on early delivery compared to the target delivery date.

7.84. In the case of NG, the potential changes to the incentive scheme applied to SO external costs suggested above would provide financial incentives for early delivery where these are in the interest of consumers. If early delivery of increases in boundary capability can reduce constraint costs, then NG can benefit through the incentive scheme applied to SO external costs.

7.85. In the case of the Scottish TOs, the arrangements set out in Chapter 6 provide a different way in which financial rewards could be available in cases where early delivery is in the interests of consumers.

7.86. We have identified potential benefits in an approach under which NG, in its role as SO, could make payments to the Scottish TOs as part of agreements to bring forward the delivery dates of work to increase boundary capability on the electricity transmission networks in Scotland.

7.87. Our intention is that these payments would allow faster delivery to be achieved in cases where a Scottish TO would incur additional costs from a faster delivery timescale but where these costs are outweighed by the benefit to consumers from faster delivery timescales. NG will be responsible for deciding whether to seek such agreements, taking account of the potential for faster delivery timescales to reduce the constraint costs that it incurs.

7.88. A proportion of any of the revenues that a Scottish TO receives through these arrangements would be passed through to consumers through reductions to the allowed revenues under the price control. This proportion would be determined by the efficiency incentive rate applied to the Scottish TO (eg if the efficiency incentive rate is 40%, then a company receiving a payment of £100 would retain £40 before tax). This is necessary to avoid perverse incentives, given that an equivalent proportion of each TO's actual expenditure will be passed on to consumers under the efficiency incentive rate.

7.89. Any payments made by NG, in its role as SO, to the Scottish TOs would be treated as SO external costs and would affect BSUoS charges.

7.90. In the case of NG, the SO and TO activities are carried out by the same company. Where NG is able to reduce constraint costs by delivering ahead of the target delivery date, it may be appropriate to allow for any additional TO costs that are needed for early delivery to be reclassified and treated as SO costs for regulatory purposes. For example, different charging methods are used to recover the TO allowed revenue and the SO external costs and it is possible that such a reclassification would allow for a fairer allocation of such additional TO costs across network users.

Provisions for non-delivery or agreed delays

7.91. As part of TOs duty to develop and maintain an efficient and coordinated system of electricity transmission we expect TOs to review on an ongoing basis the needs case for boundary reinforcement. A TO might decide, in accordance with their network development policy, that it was/is not in consumers' interests to proceed with reinforcement agreed at the time of the price control settlement. In these instances we will only seek to recover from the TO the costs avoided through non-delivery. If an applicable volume driver was in operation at the boundary, revenues would automatically adjust based on the unit costs for increasing capability agreed at the time of the price control.

7.92. In other cases, the TO may decide to defer commencing the works until a later date or a subsequent price control. In this case we would include the corresponding secondary deliverable as part of the requirements of the next price control. Again no late penalties would apply. At the same time no additional funding would be made available.

Delivery timescales spanning more than one control period

7.93. Some secondary deliverables to increase boundary capability could have a timeframe that extends into the subsequent price control period. Where possible, we will seek to break proposed boundary capability increases into stages that can be split between price control periods. If this is not sufficient we would provide commitments on elements of the funding and incentive arrangements until the projects are completed.

8. Reliability and availability - gas transmission

Chapter Summary
This chapter sets out our approach to establish outputs for gas transmission reliability and availability. This includes our consideration of primary outputs and secondary deliverables. It also sets out our decision in relation to network flexibility.

8.1. As part of RIIO-T1 we have decided to include a primary output related to the provision of gas transmission network capacity sufficient to convey gas volumes required under existing code, licence and legislative obligations on NGG. However, we do not propose to introduce a new set of financial incentives. Instead the existing commercial arrangements will remain in place subject to changes required to implement the new efficiency incentive rate and complete the SO incentives alignment work.

8.2. We have decided not to include a primary output on network flexibility as part of RIIO-T1. Instead, NGG should consider the need for expenditure in this area based on the outputs it is required to deliver over the course of the price control. We expect user commitment to drive most of the investment decisions in this area but where evidence suggests that additional investment is required, NGG will need to consider the best way to link this expenditure to RIIO-T1 outputs. We will consider the case for an uncertainty mechanism to allow us to revisit this during the control period.

8.3. In our view, if new investment is now required to support such capacity obligations under new gas flow assumptions, it would be appropriate for NGG to present evidence of the gas flow assumptions used at the time of the investment; to provide reasons why changing gas flows were not anticipated earlier; and to provide evidence as to why additional investment in system flexibility would now be required to support existing capacity in the future.

8.4. In our strategy decision document we also confirm that the secondary deliverables we proposed in December will be implemented as part of RIIO-T1. These will ensure that any risk to the future delivery of primary outputs is managed and facilitates the delivery of long-term value for money for consumers.

Reliability

Summary of consultation proposals

8.5. In December, we proposed that the primary output related to reliability in gas transmission should be for NGG to comply with its obligations to convey gas volumes at system entry and exit points in line with requirements under the Uniform Network Code (UNC), its Gas Transporter Licence (GT Licence) and, ultimately the Gas Act 1986. As such, we did not propose to introduce a new set of financial incentives. Instead the existing commercial arrangements would continue. While these do not directly incentivise delivery of this primary output, they determine the costs that

NGG faces and should provide a sufficiently strong set of incentives to encourage NGG to deliver efficiently.

8.6. The existing commercial arrangements including the caps and collars on the entry and exit buyback schemes and the overall cap of £48m would be amended by the implementation of the new efficiency incentive rates. Details on this are provided in Chapter 5 of the December document and Chapter 6 of the 'Supplementary annex - business plans, innovation and efficiency incentives'. We also said we would consider the associated SO incentives that are developed as part of the work we take forward on the alignment of incentives that the SO and TO face.

8.7. In the December document, we also sought respondents views on whether:

- there should be additional transparency with respect to the TO and SO roles that NGG performs and greater separation of these duties
- further incentives are required beyond those currently captured in the commercial and operational arrangements stipulated by the UNC and GT Licence
- the force majeure provisions for 'gas not supplied' represent best commercial practice.

Summary of responses

8.8. Those stakeholders who responded to questions in this area supported our proposed primary outputs related to reliability in gas transmission and welcomed the proposal to provide additional transparency in relation to the TO and SO roles. None of the responses commented on the other areas of our proposed approach.

8.9. On 18 February 2011, we held a meeting with NGG and representatives of shippers and storage companies. Discussions at this meeting highlighted that shippers and storage companies are broadly content with the existing incentives on the provision of gas transmission capacity. Stakeholders present at the meeting noted that they had limited concerns with respect to the force majeure provisions given that the provisions are rarely used.

8.10. We recognise from outside the price control discussions that some shippers still have concerns in specific cases.

Our decision

8.11. The primary output related to reliability in gas transmission will require NGG to comply with its obligations to convey gas volumes at system entry and exit points in line with existing requirements under the UNC, its GT Licence and ultimately, the Gas Act. Subject to Section 9 of the Gas Act, Standard Special Condition A9 of the GT Licence requires NGG to plan and develop its pipeline system to enable it to meet '1 in 20'[29] peak aggregate daily demand. The GT Licence also sets out 'baseline' capacity obligations on NGG in respect of entry and exit capacity which, subject to the provision of other conditions within the licence, NGG NTS is obliged to meet.

8.12. We anticipate that this will ensure adaptability in terms of the primary output. In this respect, if any changes are made to the UNC, licence or legislative obligations, the primary output will automatically be updated. We propose to work with gas stakeholders to develop other areas of this proposal where limited views have been expressed.

8.13. The commercial regimes for the allocation of NTS entry and exit capacity that are in place under the UNC also place firm obligations on NGG NTS to meet the new capacity needs of NTS users. We will implement our efficiency incentive rates to these cost categories (including removal of caps/collars) and we expect NGG to consider the implications that this will have as part of its July 2011 business plan.

8.14. NGG's licence sets out the default investment lead times for the provision of additional entry and exit capacity. The default lead time for entry is 42 months and for exit is 36 months. NGG is incentivised to deliver incremental capacity ahead of these lead times via both the permit scheme and the additional capacity revenues it generates.

8.15. In November 2009 we concluded our review of the entry capacity operational buy-back incentive and default incremental entry capacity lead time[30]. We decided to defer any review of the default incremental entry capacity lead time until the next full price control period ie RIIO-T1.

8.16. NGG will need to include in its business plan a justified proposed position for the entry [and exit] default lead time. We will then consider this in further detail.

8.17. In addition to the outputs set out above we also need to consider outputs related to further sources of network flexibility eg diurnal flows at entry and exit and varying flows across the network. We will require NGG to report additional information and develop associated outputs to which they will need to link expenditure in order to justify any proposed investment in these areas.

8.18. We expect NGG to work with stakeholders on force majeure provisions to understand, as it develops its business plan, whether these represent best commercial practice and, if not, what changes might be needed.

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[29] '1 in 20' peak aggregate daily demand is the current performance requirement and means the level likely to be exceeded (whether on one or more days) only in 1 year out of 20 years having regard to historical weather data derived from at least the previous 50 years and other relevant factors.
[30] Paragraph 1.5, Review of Entry Capacity Operational Buy-back Incentive and Default Incremental Entry Capacity Lead Time , Consultation, Ofgem, 25 February 2009. This is available on our website at http://www.ofgem.gov.uk/Networks/Trans/GasTransPolicy/EntryCapacity/Documents1/Buy%20back%20and%20lead%20times%20consultation.pdf

Network flexibility

8.19. We do not propose to include a primary output on network flexibility as part of RIIO-T1. Instead NGG should consider the need for expenditure in this area based on the outputs it is required to deliver over the course of the price control.

Summary of consultation proposals

8.20. In the December document, we expressed concerns that NGG may not receive sufficient investment signals from the entry and exit capacity booking arrangements to meet NTS user capacity needs efficiently under all future gas flow patterns. In addition, we noted the obligation on NGG to invest to meet '1 in 20' peak aggregate daily demand but had concerns that this also may not facilitate the necessary investment signals. We therefore invited views on whether the proposed primary output related to reliability which would require NGG to meet '1 in 20' peak aggregate daily demand would ensure that sufficient system flexibility was secured.

8.21. In the December document we explained that, in response to the Forecast Business Plan Questionnaire (FBPQ) for the fourth Transmission Price Control Review (TPCR4) rollover in October 2010, NGG had indicated that it had identified a significant need for system flexibility investment in the period 2012-13 to 2017-18. We proposed that NGG should link any such proposed expenditure on flexibility to outputs set out in its well-justified business plan and that any proposals must be justified by supporting indicators and robust supply and demand modelling assumptions.

8.22. We sought respondents' views on this approach. We also sought views on our proposal to require NGG to develop and implement a system flexibility monitoring regime building on the flexibility indicators developed during its System Flexibility workshops in 2009 and 2010 which would identify and support any future system flexibility investment plans. We noted that NGG and the GDNs should give explicit consideration to optimising investment efficiency across the NTS/GDN interface in formulating their business plans.

8.23. In parallel to our December document we published a wider consultation on issues relating to system flexibility titled 'Update consultation on National Transmission System (NTS) flexibility capacity'.[31] We used this consultation to seek industry views on, among other things:

- a common definition of NTS system flexibility
- the value of the system flexibility indicators developed by NGG following the implementation of Exit Reform
- our analysis of the factors likely to affect future NTS gas flows

[31] Updated consultation on National Transmission System (NTS) flexibility capacity, Ofgem, 16 December 2010. This is available on our website at http://www.ofgem.gov.uk/Networks/Trans/GasTransPolicy/Documents1/System%20flexibility%20on%20the%20NTS%20081210.pdf

- the need for system flexibility investment
- the principles that should apply to allocating and funding investment for future system flexibility.

Summary of responses

8.24. Most respondents considered the definition of NTS flexibility was important to an understanding of user requirements and system investment needs. NGG agreed with our view that system flexibility is the ability to meet national and local supply and demand imbalances. They clarified that system flexibility could also refer to the ability to meet day to day changes in national and locational supply and demand patterns including the management of linepack and the consideration of security of supply issues. A number of respondents agreed with NGG that an important distinction should be made between the ability to manage linepack fluctuations within day and seasonal fluctuations in supply and demand.

8.25. Many of the respondents considered that further analysis of the need for investment in system flexibility was required before funding arrangements or changes to flexibility capacity allocation mechanisms were considered.

8.26. A number of respondents highlighted the need for full details on:

- existing flexibility availability and usage
- NGG's rationale with respect to the need for more flexibility
- the costs of the projects that NGG considers to be necessary.

8.27. Most of the respondents agreed with our summary of the supply and demand factors which may affect future NTS gas flows, but a number of shippers and GDNs considered that uncertainty surrounding future demand for flexibility meant that anticipatory investment carried the risk of being inefficient. These respondents considered that it would be appropriate to undertake further analysis and monitoring of system trends before large investment projects were triggered.

8.28. Respondents agreed that if the case for new investment to support flexibility was proven, it would be appropriate to link the investment to outputs within the RIIO-T1 framework. Many considered that where possible such investment should be linked to confirmed demand signals. NGG considered that although investment should be linked to user signals, it may not be possible to link all investment to specific outputs.

8.29. Respondents agreed that the flexibility indicators developed by NGG in its System Flexibility workshops during 2009 and 2010 could provide useful information about trends in system flexibility, but a majority disagreed that the indicators would be capable of identifying future investment needs. NGG considered that the indicators provide a useful view of historical trends but do not provide a forward looking view of future requirements. A majority of GDNs and shippers, as well as a customer representative, were concerned that the indicators should not be considered in isolation and that a simple extrapolation of trends should not be used to identify investment needs.

Our decision

8.30. We do not propose to include a primary output on network flexibility as part of RIIO-T1. Instead NG should consider the need for expenditure in this area based on the outputs it is required to deliver over the course of the price control. We expect user commitment to drive most of the investment decisions in this area but where evidence suggests that additional investment is required, NGG will need to consider the best way to link this expenditure to RIIO-T1 outputs. We will consider the case for an uncertainty mechanism to allow us to revisit this during the control period.

8.31. A key part of the NTS entry and exit capacity allocation arrangements is the user commitment principle. In our view, financially backed user commitment investment signals provide the most reliable basis for investment decisions. An appropriate commitment by NTS users to paying charges in respect of incremental capacity improves NTS investment signals (reducing the risk of stranded assets emerging on the network) and in so doing promotes security of supply. The investment signals which NGG receives in respect of incremental capacity through the user commitment framework helps NGG optimise its investment decisions. NGG should be able to connect the information it receives from the entry and exit commercial arrangements to its system flexibility investment plans, and relate these to RIIO-T1 outputs.

8.32. In recent years NGG has received significant revenue driver funding in respect of incremental entry capacity. A significant proportion of this investment has been to support new entry capability at LNG import terminals such as Milford Haven and Isle of Grain. NGG has indicated that the assumptions used to model the capacity costs of supporting the incremental capacity at the time of the investment may not have been capable of capturing the capacity costs forecast under future gas flow scenarios. In our view, if new investment is now required to support such capacity obligations under new gas flow assumptions, it would be appropriate for NGG to present evidence of the gas flow assumptions used at the time of the investment; to provide reasons why changing gas flows were not anticipated earlier; and to provide evidence as to why additional investment in system flexibility would now be required to support existing capacity in the future.

8.33. In respect of system flexibility investment which NGG considers may be required to support future incremental exit and entry capacity signals (as opposed to existing entry and exit capacity obligations), we consider that it would be appropriate for the cost of this investment to be apportioned to NTS users in a cost reflective manner and to be funded through the release of revenue drivers in respect of incremental capacity. It may be appropriate for NGG to review its commercial and capacity charging arrangements and its revenue driver requirements to align them with this objective. But, in our view, financially backed user commitment investment signals provide a more robust basis for investment decisions than anticipatory investment forecasts. Further, where such costs are represented in capacity charges, users' willingness to commit to paying such charges provides an appropriate proxy for the extent to which they value the service and the extent to which it would therefore be efficient to undertake the investment.

8.34. In their responses to our updated consultation on system flexibility, NGG and other respondents considered that there may be difficulties associated with attributing deep system reinforcement costs to specific entry or exit capacity signals. Where proposed system flexibility investment cannot be related to user signals, we consider that it would be appropriate for NGG to explain why this is the case in its analysis of the need for the investment, and, in the absence of user signals, what other drivers for the proposed investment they have used.

8.35. We consider that the system flexibility indicators developed by NGG in its System Flexibility workshops during 2009 and 2010 are capable of identifying gas flow trends on the NTS, but we agree with respondents to our system flexibility consultation that, in isolation, they would be unlikely to be capable of identifying the need for system flexibility investment. Our preference is that system flexibility investment decisions are informed by incremental entry and exit capacity user signals. In the absence of clear signals the indicators may be capable of indicating future system flexibility trends, but we would expect such data to be interpreted and analysed by NGG in conjunction with other supply and demand forecasts. For this reason, we consider that the system flexibility monitoring regime established by NGG following implementation of Exit Reform is sufficient and, providing NGG continues to develop these arrangements, we do not consider it appropriate to replicate the obligation within the RIIO-T1 framework. We also note that, in consultation with industry, the indicators that NGG consider it would be appropriate to monitor may change over time. If the monitoring regime became a licence obligation it may lack sufficient adaptability to respond to these changes.

NTS exit (flexibility) capacity

8.36. GDNs use localised and aggregate capacity tools to manage the diurnal or within day profile of demand on their networks. These tools can take the form of physical assets or commercial instruments and are broadly:

- interruption of large customers
- use of gas storage holders and
- linepack depletion and subsequent recovery from the LTS or from NGG via NTS exit (flexibility) capacity bookings.

8.37. In our December document we indicated our concern that the current flexibility capacity arrangements do not allow GDNs to compare the costs of procuring incremental NTS exit (flexibility) capacity from NGG and that this may be inhibiting the system wide efficiency of capacity management investment decisions across the NTS/GDN interface.

8.38. Beginning in November 2010, we have hosted a series of meetings known as the 'Capacity Working Groups' involving the GDNs and NGG. The meetings have addressed various issues relating to capacity output and reliability measures. In particular they have also considered ways of improving the efficiency of investment across the NTS/GDN interface in respect of incremental NTS exit (flexibility) capacity.

8.39. To address the concerns expressed in our December document, at the fourth capacity working group meeting on 10 February, the GDNs and NGG provisionally agreed a process and timetable which would facilitate an information exchange necessary to allow comparative analysis of the relative costs of meeting an incremental GDN requirement for NTS exit (flexibility) capacity or Assured Offtake Pressures (AOPs). The process will effectively replicate the stages of the annual Offtake Capacity Statement (OCS)[32] process to a timetable which will allow the GDNs and NGG to take account of the results of the analysis in submitting their well-justified business plans in July 2011. The process is not a replacement for the annual OCS process, but the provisional agreement requires GDNs to provide NGG with offtake specific information as per their analysis requirements by 1 March 2011 and NGG to provide details to the GDNs of any offtake specific pressure reductions requests it may have, also by 1 March 2011 (this process is underway). Following analysis, by 31 May 2011, NGG will then provide information to the GDNs on the costs of meeting any additional pressure or capacity requests, and the GDNs will provide information to NGG on the costs they would incur in meeting any pressure reductions. It is hoped that this information will allow the companies to determine the most efficient capacity options available in formulating their business plans.

8.40. Notwithstanding the potential for any incremental NTS exit (flexibility) capacity investment, NGG and the GDNs have also identified measures which could be taken to improve the efficiency and transparency of the existing OCS process. These include potentially incorporating increase and decrease requests to AOPs within the process, and the companies have indicated their intention to develop these proposals including proposing changes to the UNC where appropriate. The companies have also identified that where analysis indicates that it would be efficient for NGG to provide incremental NTS exit (flexibility) capacity to the GDNs, the definition of this capacity in relation to prevailing NTS exit (flexibility) capacity; the user commitment applying to the capacity; its representation in NGG's charging methodology; and its compatibility with the existing OCS process would have to be considered.

8.41. We continue to consider that it would be appropriate for NGG and the GDNs to make explicit consideration of optimising investment efficiency across the NTS/GDN interface in formulating their business plans. We support the process NGG and the GDNs have agreed in order to establish comparative costs of any investment required in respect of meeting GDNs linepack requirements.

8.42. However, we note that our decision on any investment proposals made by NGG or by the GDNs will be subject to scrutiny of each of the companies' network analysis and demand modelling assumptions. We also recognise that consideration of the commercial arrangements applying to the release of any incremental NTS exit (flexibility) capacity may be required. In the interests of transparency and efficiency we consider that it would be appropriate for any such arrangements to be represented in the UNC and within NGG's exit capacity charging methodology and its

[32] An Offtake Capacity Statement describes the amounts of flat and flexibility offtake capacity available.

exit capacity release (ExCR) methodology statement. We consider that there is sufficient time for these arrangements to be developed following submission of the companies' business plans, and we do not think it would be appropriate to recommend changes to the NTS exit (flexibility) capacity arrangements at this stage.

Funding arrangements and commercial implications

8.43. In the section above we set out our views on the importance of user signals to investment decisions. In our view, if the incremental entry and exit capacity signals received by NGG do not currently provide them with appropriate system flexibility investment signals, it would be appropriate for NGG to review its charging methodology and its capacity release arrangements to align them with this objective where possible. The responses to our update consultation on system flexibility revealed opposition to the possibility of the introduction of a separate flexibility capacity product for NTS users, and identified some of the difficulties associated with defining and implementing such a product. In advance of further analysis of the extent to which NTS flexibility is likely to become scarce, it would not be appropriate for us to mandate specific changes to the NTS commercial arrangements. But we do consider that it is NGG's responsibility to ensure that the arrangements are providing them with appropriate investment signals, and that the capacity charges levied on NTS users reflect the costs they impose on the system.

8.44. Where NGG identifies difficulties in attributing system flexibility investment to specific entry or exit capacity signals and proposes new system flexibility investment as part of its July 2011 business plan, we would expect these proposals to be linked to outputs and justified by supporting indicators and robust supply and demand modelling assumptions. In the event that we approve system flexibility funding as part of the RIIO-T1 settlement, we would seek to incentivise efficient delivery of this investment. Given the uncertainty of the forecasts which may affect the need for this investment, we would also be prepared to consider a capex reopener provision where new evidence concerning the need for system flexibility investment came to light following the publication of final proposals. We will consider the detail of these arrangements following scrutiny of NGG's July 2011 business plan submission.

Secondary deliverables

Summary of consultation proposals

8.45. Our consultation proposal was that the long-term delivery of the primary outputs should be ensured through secondary deliverables relating to asset health, criticality and replacement priorities/risk. The framework and incentives for these deliverables should be the same as that used in electricity transmission (see Chapter 6). While the assets are clearly different, the asset health and criticality measures apply the same framework. For example, the asset health measure will, as in electricity, grade the health of assets and involve the same reporting requirements.

Summary of responses

8.46. One respondent noted that the secondary deliverables for asset risk require further development in gas transmission but considered that this is achievable in the timescales set out.

8.47. A number of respondents made general comments on the asset health and criticality measures which are summarised in Chapter 6. However, we received no other gas specific comments.

Our decision

8.48. Our decision is unchanged from our December document. These secondary deliverables will ensure that any risk to the long-term delivery of the primary output is managed and facilitate the delivery of long-term value for money for existing and future customers.

8.49. In gas transmission, NGG should pursue a system-wide risk assessment over the long term to justify investment in assets that impact on the reliability and safety of the network or the environment. NGG has highlighted that they do not make investment decisions based upon an overall measure of network risk and take into account a range of factors when prioritising investment programs. We note that the TOs make asset management decisions trading off resource impacts and risk on a daily basis, but we consider it important that they have a more consistent framework for articulating this.

8.50. An asset Health Index provides a framework for collating information on the health (or condition) of network assets. Criticality provides a measure of the consequence of failure of assets typically measured in terms of system, safety and the environmental implications. By combining asset health and criticality, TOs can develop risk indices that determine capital replacement priorities.

8.51. NGG currently reports on measures of asset health and criticality under Licence Special Condition C13 NOMs. However, we consider that these measures should be further developed for RIIO-T1 to provide a more consistent framework to that outlined for electricity transmission (and developed as part of DPCR5). Appendix 2 contains further information on our developments for RIIO-T1.

8.52. In the short term (including in RIIO-T1), we expect NGG to be able to articulate how they use other risk management processes in conjunction with our proposed secondary deliverables (asset health, criticality and replacement priorities) when making asset management decisions. This should demonstrate:

- how the TOs make the case for spending a marginal pound across different asset categories (for example, they should describe how risk trade-offs are made between different assets)

- how trade-offs are made between areas of expenditure (load, non-load, capex and opex).

9. Conditions for connections

Chapter Summary
This chapter sets out our strategy decision on the primary output and financial incentives for timely connections including the rationale underpinning this decision.

9.1. The RIIO-T1 framework includes an output category related to performance in connections which is intended to encourage timely provision of connections in both electricity and gas transmission.

9.2. There are a number of existing obligations related to connections in electricity transmission and we have reached the decision that the primary output should be a requirement to meet these existing obligations. This includes the provisions established as part of the recent 'Connect and Manage' arrangements and the timescales for the delivery of a connection set out in the TO licence.[33]

9.3. While there is scope to initiate enforcement action in the event of a breach of the timescales specified in the licence, we propose to implement provisions to allow for specific financial penalties where these time periods are exceeded. The incentive would be downside only and equivalent to 0.5% of allowed base revenue.

9.4. Similarly, in gas transmission there are existing obligations on the provision of connections. These include an overall timescale for NGG to enable incremental entry /exit capacity which is supported by commercial incentive arrangements, eg Special Condition C8D: NTS gas entry incentives, costs and revenues. Consistent with our approach in electricity, we have reached the decision that the primary output in gas transmission should reflect the requirement on the TO to comply with these obligations. We do not plan to introduce any financial incentive on the RIIO-T1 primary outputs.

9.5. We are aware of possible changes to the gas transmission arrangements which are being considered as part of a parallel industry process. We note that the relevant parties are aiming to implement these changes well before April 2013 and therefore at the time RIIO-T1 commences the primary output definition for connections should reflect the latest industry position including any financial incentives in place.

9.6. We would note that it is not only timeliness of connection provision that is important in gas and electricity transmission but also the quality of connections work. We intend to make sure that specific questions regarding the quality of connections are included in the customer/stakeholder survey (see Chapter 5).

[33] For example in standard licence condition C8 'Requirement to offer terms' in NGET's licence.

Summary of consultation proposals

9.7. In our December document we proposed to implement a primary output related to timely delivery of connections for both electricity and gas transmission.

9.8. We noted that, in conjunction with Project TransmiT in electricity transmission, we had already issued an open letter[34] seeking the views of interested parties on various issues associated with connections. The consultation asked a number of questions designed to inform us of any problems related to timely delivery of connections and to determine whether stakeholders had concerns in this area.

Summary of responses

9.9. Responses to the TransmiT open letter[35] and the December document confirmed the importance of timely delivery of connections in both electricity and gas. Respondents highlighted that when considering a primary output in this area it is difficult (and in some cases may have undesirable consequences) to separate the timeliness of delivery in connections from the quality of the company's overall connections work.

9.10. Consistent with our previous discussions with stakeholders, respondents also highlighted uncertainties in this area. In particular, many respondents set out that it was too early to judge whether any problems in connections remain, given that the full Connect and Manage arrangements have only recently been implemented.

9.11. Timely connections in electricity transmission was recognised as important. Respondents noted that no connection is typical and therefore the use of fixed average timescales for elements of, or the entirety of, the connection process would not be appropriate. Some respondents highlighted the importance that should be attached to the agreement reached between the promoter and the TO in terms of the timescale for the connection. They suggested that encouraging timely and consistent delivery of agreed deadlines should be considered a primary output. Some stakeholders also highlighted the importance of taking account of the impact of exogenous influences, particularly those associated with the planning regime.

9.12. Respondents noted that it would be important to align the decisions that we take with respect to a primary output for connections in electricity transmission as part of RIIO-T1 with any conclusions we reach on the commercial regime as part of Project TransmiT. A number of respondents also noted that it may be worth waiting until the Connect and Manage arrangements have properly bedded down before taking a final decision in this area.

[34] Consultation on the issue of timely connection to the electricity transmission network, 14 December 2011, this is available on our website at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=77&refer=Networks/Trans/PT.
[35] Project TransmiT is Ofgem's independent and open review of transmission charging and associated connection arrangements. More information is available on our website at: http://www.ofgem.gov.uk/Networks/Trans/PT/Pages/ProjectTransmiT.aspx

9.13. In gas transmission, stakeholders highlighted the different processes associated with the connections arrangements and suggested possible improvements to make these more joined up. Similarly to the views expressed with respect to electricity transmission, respondents noted the importance that should be attached to the receipt of assurances that the TO will be able to meet agreed timescales rather than being concerned about the delivery of faster connections per se. Stakeholders made reference to the parallel industry work that may lead to changes in the current arrangements, particularly the proposed introduction of a formal connection offer process.

9.14. Some stakeholders have also suggested that in gas transmission NGG may need to do more to support the changes.

Our decision

9.15. It is imperative that electricity and gas transmission network companies give due priority to ensuring timely connection to their networks. Past experience in electricity has shown how significant this can be in terms of overall TO performance.

9.16. We have reached the decision that the primary output for connections in both gas and electricity transmission should be related to compliance with current obligations. In electricity, given the importance of timely connections with respect to the delivery of a sustainable energy sector, we intend to introduce a financial penalty equivalent to up to 0.5% of allowed base revenue which may be applied if required timeframes[36] are exceeded. The Authority would decide whether to apply the financial incentive given the circumstances involved. For example there might be valid reasons for delay. However, it would consider this on annual basis for each of the TOs and take into account promoters' views. In the case of the Scottish TOs such a problem should be highlighted via the consumer survey and GEMA would need to consider this in deciding whether to apply such a penalty.

Electricity transmission

9.17. The TOs should strive to deliver timely connections and, to encourage this, we have decided to establish a primary output related to compliance with existing obligations. As above, a financial penalty may be applied where the timings set down in the licence or codes are exceeded.

9.18. We note the major reform that has taken place in electricity transmission to seek to address concerns associated with the delivery of timely connections. We acknowledge the views of many stakeholders that it is too early to judge the impact that these reforms have had. We think that timely delivery of electricity transmission connections could be compromised unless we reinforce the timings for the development of a connections offer.

[36] For example as required of NGET through standard condition C8.

9.19. We also intend to build on the reporting obligations that we plan to establish as part of Project TransmiT.[37]

9.20. We do not however agree with the view that our conclusions, particularly on any additional financial incentives would need to await and reflect the final conclusions of Project TransmiT. While there were synergies in inviting views in parallel related to the commercial arrangements, to which project TransmiT relates, and the price control outputs at the start of the respective projects, we do not think there is a link between these projects going forward. Indeed, responses to our consultation letter did not identify that this was the case. The RIIO-T1 primary output on connections and associated financial incentive should reflect general performance levels rather than particular customer needs.

9.21. We recognise that there are no typical connections in electricity transmission and that it is therefore not desirable to apply financial incentives to encourage faster delivery across the board. There also does not appear to be an easy classification that would allow us to set fixed timescales for the delivery of a connection without the potential for unintended consequences to arise, for example, incentivising poor quality work or early delivery that is not then valued.

9.22. At this stage we propose to implement a financial incentive with respect to the delivery of connections in electricity transmission, which is downside only. This would reinforce the obligations. We will continue to work during the price control review in determining the precise basis for the financial penalty. For example, it might consider the number of occasions that set times are extended. This work will take into account any reporting obligations put in place as a result of Project TransmiT and other developments.

9.23. We note that as well as timeliness of connections work, quality is also important. We intend to make sure that specific questions in this area are included in the customer/stakeholder survey that is developed as part of the primary output on customer satisfaction (see Chapter 5).

9.24. We recognise that, particularly for the Scottish TOs, the customer/stakeholder feedback is likely to be heavily influenced by TO performance on connections, not least timeliness of delivery. We intend to include separate questions to identify any stakeholder concerns in this area for both the Scottish TOs and NGET.

9.25. An important part of a TO's business plan development is how it uses information obtained through its stakeholder engagement. We would therefore encourage TOs to work with stakeholders to consider if there are any further actions they could take to improve timeliness of connections.

[37] The letter is available from our website at:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=92&refer=Networks/Trans/PT

Gas transmission

9.26. Similarly to electricity, in gas we think that a primary output related to timely delivery of connections should be defined with respect to existing obligations. This should also reflect any subsequent changes to the arrangements that result from currently industry discussions that are taking place.

9.27. In gas, there are already financial incentives in place associated with the provision of incremental entry and exit capacity. We understand from stakeholders that a key concern is the absence of a formal process for the offer of a connection from the NTS. As a result, shippers have proposed the establishment of a working group to consider these issues related to connections processes.[38] The indicative timing for this work is to have a process in place for April 2012.

9.28. At this stage we do not propose to introduce any new financial incentives but recognise that industry changes might need to be reflected in this area.

[38] Joint Office of Gas Transporters proposal 0373 'Governance of NTS connection processes, 11 March 2011. Details of this can be found at: http://www.gasgovernance.co.uk/sites/default/files/Modification%200373.pdf.

Appendices

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Appendix 1 - Consultation Questions and Responses

1.1. Responses received by Ofgem which were not marked as being confidential have been published on Ofgem's website www.ofgem.gov.uk. Copies of non-confidential responses are also available from Ofgem's library.

1.2. The following is a summary of those responses which were received.

Chapter 1 - Introduction and context

Question 1: Do you have views on the approach we have undertaken in developing the outputs framework?

1.3. One TO thought that the development of outputs was lagging behind schedule. They thought that Ofgem needed to do further work ahead of submission of business plans to fully develop outputs and associated incentives with analysis from the companies. They also thought that July 2011 submission of business plans might be better seen as a stepping stone for finalised business plan in March 2012.

1.4. Another TO had concerns about the rapid development of outputs. In their opinion involvement of a wider range of stakeholders in the outputs working group had meant that not enough time has been spent discussing the detail. Consequently they had concerns that the timeline is jeopardising the ability to agree the scope and principles underlying the outputs. Given that the implementation of RIIO-T1 is more than two years away they thought the timetable was too ambitious and an unnecessary risk. They thought another six months was needed to design and develop clear outputs.

1.5. A renewables industry group thought that there had been good process of stakeholder engagement in the development of the outputs. The wanted to see more information about Ofgem's assessment of the proposed outputs against the criteria set out in the RIIO handbook. They thought it was important that this assessment should determine the set of outputs rather than any pre-judged assumptions about what outputs are needed/not needed.

Question 2: Do any of our proposed output measures present potential difficulties in ensuring the submission of accurate and comparable data?

1.6. One TO thought that there could be difficulties in reporting data in relation to outputs on losses caused by TOs, wider works and constraints. This was because these areas are not readily observable so will need some modelling to provide estimates of TOs' contribution or anticipated requirements. It would also take some time to develop consistent methodologies for companies to undertake this modelling.

1.7. One TO said that the output measures were not developed enough for it to assess if there will be any difficulties reporting data.

1.8. A renewable industry group said that there was insufficient detail to assess whether there would be any difficulties. They noted that focus should be on the getting the reporting requirements right on the outputs that are most material for the high level objectives of the RIIO model rather than business as usual (BAU) measures.

Question 3: Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?

1.9. One TO thought there was a risk that some output measures, such as wider works and network performance, could collapse to input-based regulation which would be onerous to both provide and verify. This could also stifle innovation.

1.10. Another TO suggested that the reporting requirements are likely to be more onerous owing to the increase and sophistication of outputs. They thought reporting requirements should demonstrate a clear business benefit.

1.11. A renewable industry group said that all reporting has costs so it was appropriate to focus on the important few.

Question 4: Do you have any views on whether, in principle, it is appropriate to consider requiring the companies to do more to verify their regulatory reports?

1.12. One TO suggested that further development of outputs will address issues. They also thought that any extra costs due to verification processes would need to be well justified.

1.13. Another TO said that there was little to suggest that the current process needed to be changed as it was working well. They opposed another costly overhead.

1.14. A renewable industry group thought that the approach should be similar to good practice in other industries.

Question 5: Should we introduce an independent examiner for the TOs to improve regulatory reporting?

1.15. A TO said that Ofgem was at liberty to appoint a independent reporter to verify returns but that they would require extensive experience to assess correctly.

Question 6: Do you have any views on our proposed approach to revising outputs?

1.16. A TO thought there might be a need to include additional provisions for revising outputs, for example if incentive leads to exceptionally high (and undeserved) penalties.

Chapter 2 - Safety outputs and incentives

Question 1: Do you have any views on the primary output and secondary deliverables for electricity and gas transmission safety?

1.17. All TOs agreed with our primary output and secondary deliverables for electricity and gas transmission safety.

1.18. Two environmental groups noted that safety is of paramount importance but is subject to existing legal requirements and so questioned its inclusion as a RIIO regulatory output.

1.19. The HSE generally agreed with our proposed safety outputs in electricity and gas transmission. It noted that the legislative framework for electrical safety does not require the TOs to report on a set of metrics for measuring compliance against legal safety obligations and recommended considering a broader set of metrics. It recognised our intention to support rather than duplicate HSE's functions and noted that it will further consider what advice it can provide the TOs in developing the safety elements of their business plans.

Question 2: Are these appropriate areas to focus on and are there any other areas that should be included?

1.20. One TO commented that it also considering other areas which could be covered with the definition of leading secondary delivery indicators and intend to develop these potential options as part of its well justified business plan.

Question 3: Do you agree with the proposed approach to setting safety incentives?

1.21. All TOs agreed that it is not appropriate to attach financial incentives to the primary safety outputs since we are incentivised by other agencies and mechanisms, particularly the HSE.

Chapter 3 - Reliability and availability - electricity transmission

Question 1: Do you have any views on the primary output and secondary deliverables for electricity reliability and availability, including:
(1) are these appropriate areas to focus on?
(2) are there any other areas that should be included?
(3) do you agree with the proposed approach to setting reliability incentives?

1.22. One TO:

- Agreed that the appropriate primary reliability outputs are Energy Not Supplied (ENS) and constraints since they directly measure the impact of unreliability on customers.
- Argued that the key parameters in terms of setting reliability incentives on the ENS scheme are the baseline and the incentive strength. On incentive strength, this TO agreed that the current incentive strength of approximately £33,000 per MWh is above the value that customers place on being without supply.
- Agreed that secondary (leading) delivery indicators are required to ensure that asset health related network risk is being appropriately managed. Although the TO appreciates the need to evolve NOMS over time, it does not agree that the majority of the changes as proposed.
- Generally agreed with proposed exclusions to ENS.

1.23. Another TO:

- Agreed that Energy Not Supplied (ENS) is an appropriate primary measure of the performance of the transmission network. However it should be recognised that this measure is not directly within the control of Scottish TOs.
- Considered that the combination of asset health, criticality and replacement priority are the main secondary deliverables which should be considered. The other factors of circuit unreliability, system unavailability, system faults and asset failures are less important and where it may be helpful to monitor these areas, they are less important to delivery of the investment plan in Transmission.
- Argued that the incentive mechanism should be fully symmetrical offering rewards as well as penalties. It did not agree that there should be no collar applied to the ENS incentive and that to provide a fully symmetrical incentive a collar equal to double the target is required to ensure that TOs are exposed to the same level of penalty as reward.

1.24. Another TO supported in principle the proposal to incentivise performance based upon energy not supplied (ENS) using the calculation for NG's existing reliability incentive. However, its support was subject to three qualifications:

- That only controllable events are included in the calculation;
- Targets are set based not on historic performance but on forecast performance during the period taking into account increased system risk associated with the large capital investment programme; and
- The strength of the incentive reflects the materiality of ENS and the TO's risk profile during the RIIO-T1 period.

1.25. One environment group agreed that the current level assumed for the value of lost load for incentivising transmission system security is too high.

1.26. Another environment group generally supported the ENS incentive. However it would be concerned if this and the secondary measures were to produce perverse outcomes detrimental to other objectives. It notes that innovations, smart grids, connect and manage and reducing constraints all involve new risks, and whilst we would expect TOs to manage those risks, the incentive must not diminish progress toward these other activities.

Question 2: Do you have any views on our proposed treatment of different loss of supply events when calculating energy not supplied (ENS) including:
(1) events lasting three minutes or less?
(2) events that cause electricity not to be supplied to three or fewer directly connected parties?
(3) events resulting from actions to ensure public safety, third-party damage, severe weather and other exceptional events?
(4) planned outages?
(5) events on an adjacent system?

1.27. One TO generally agreed with our proposed treatment of loss of supply events. Another noted that only controllable events should be included in the calculation.

1.28. One TO disagreed with the proposed approach for treatment of events triggered on an adjacent system. It argued that the DNO IIS incentive scheme has been used as a benchmark throughout the working group development of the ENS proposal and should also be used for transmission.

Question 3: Do you have any views on our proposed options for applying financial consequences in the case of material under or over delivery of secondary deliverables?

1.29. One TO argued that is essential that material under or over delivery of secondary deliverables is measured against the profile of asset replacement priorities (based on asset health and criticality) at the end of the RIIO-T1 period. It noted that it would appear appropriate to achieve symmetry between the treatment of the financial consequences of under and over delivery.

1.30. Another TO agreed with the principle that financial consequences may apply in cases where there is clear and material under or over delivery and that these options are based on either revenue adjustment at the end of RIIO-T1 or to begin RIIO-T2 on the assumption that the TOs have achieved agreed levels for the deliverables.

1.31. One TO did not support a financial incentive on asset health.

Question 4: Do you agree with our proposed approach to incentivising the TOs for the impact of planned outages on constraints, including:
(1) is it appropriate to incentivise TOs?
(2) if so, should the incentive be broadened to other areas - for example, unplanned interruptions?
(3) are the confidentiality issues around constraint costs material and if so, how might they be resolved?
(4) is there a need to review the procedure for incorporating the full cost of cancellation to the TOs?

1.32. One TO said that in principle "constraint costs attributable to TOs actions should be incentivised" but recognise that "there are clearly a number of significant practical issues that would need to be addressed". They also say that "constraint costs caused by unplanned outages are not particularly material" and say that incentive arrangements for these costs are only reasonable if this can be achieved with minimal burden. They did not consider the confidentiality issues relating to Scottish TOs to be "insurmountable" and point out that these issues are currently being reviewed by the Commercial Balancing Services Group. They also agree that it is appropriate to review the procedure for incorporating the full cost of cancellation.

1.33. One TO said that they were open to discuss an incentive based on minimising constraints but had concerns if system access to carry out replacement/refurbishment took a back seat to constraint minimisation. The TO said that where constraints are caused by planned circuit outages that are necessary for asset replacement and refurbishment, the latter should take precedence and the TO should not be punished. If there is an opportunity to shorten duration of outages safely, there should be a fair sharing of any constraints saving between SO and TO. If an incentive scheme is based on actual constraints, it would be essential all TOs to have transparency on constraint costs, which Scottish TOs currently lack.

1.34. Another TO thought there should be transparency in around constraint information, and are willing to work with the SO to develop a reporting mechanism related to actual outages. The TO supported further enhancement of the TO/SO interactions for outage planning. They did not support placing a financial incentive on TOs to minimise investment related constraints and operational/outage related constraints or any proposal by Ofgem to expose the TO to a proportion of the SO's outage related constraint costs. They noted that BETTA prevents Scottish TOs from having relevant market information.

1.35. A large user thought TOs should be incentivised to minimise constraint costs and think there is a case for exposing Scottish TOs to proportion of constraint costs, though recognise confidentiality issues. In England and Wales, they believe that alignment of efficiency incentive rate/sharing factors would provide a better framework for managing constraint costs.

1.36. A consumer group consider that aligning SO and TO schemes might be more difficult on electricity than on gas. Partially this is because the electricity SO scheme has been less demonstrably fit for purpose in recent years, with ex post costs often wildly different from ex ante estimates. In addition, the electricity system is likely to be subject to greater change than gas in the coming years. This may make setting long term SO schemes difficult (ie greater risk that out-dated targets/outputs could become locked in for an extended period). If Ofgem can find pragmatic ways to tackle these risks, there is value in further exploring ideas around SO/TO alignment.

1.37. Two renewable industry groups thought it is important for TOs to take appropriate measures to reduce constraints. However they noted concerns that a specific financial incentive will result in delays to “Connect and Manage” connections as this is by far the quickest and easiest way of controlling constraints. The "Connect and Manage" regime is very flexible and open to interpretation but there was a lot of scope for including or excluding schemes at the margins. They noted that the RenewableUK’s proposal for an alternative, broader output measure/incentive scheme Low Carbon Economy Incentive would provide an incentive to reduce constraints wherever these aided the low carbon economy which would generally be the most expensive and common constraints.

Chapter 4 - Reliability and availability - gas transmission

Question 1: Do you have any views on the primary output and secondary deliverables for gas reliability and availability:
(1) are these appropriate areas to focus on?
(2) are there any other areas that should be included?
(3) do you agree with the proposed approach to setting reliability incentives?

(including from separate parallel consultation on system flexibility)

1.38. Those stakeholders who responded to questions in this area supported our proposed primary outputs related to reliability in gas transmission

1.39. In their responses a majority of respondents considered that the definition of NTS flexibility was important to understanding user requirements and system investment needs. NGG agreed with our view that system flexibility is the ability to meet national and local supply and demand imbalances, but they considered that it was also the ability to meet day to day changes to national and locational supply and demand patterns; the management of linepack and the consideration of security of supply issues. A number of respondents agreed with NGG that an important distinction should be made between the ability to manage linepack fluctuations within day and seasonal fluctuations in supply and demand.

1.40. A majority of respondents considered that further analysis of the need for system flexibility investment was required before funding arrangements or changes to flexibility capacity allocation mechanisms were considered. Notwithstanding remedial UNC changes which could be made to improve the efficiency of the offtake capacity statement (OCS) booking process[39], this consensus view applied equally to the provision of NTS exit (flexibility) capacity allocated to GDNs as to the provision of system wide flexibility necessary to cope with aggregate gas flow variations.

1.41. A system operator of a gas network downstream of the NTS considered that full details of existing flexibility availability and usage; the reasons why NGG considers more flexibility is required; and the costs of the projects it considers necessary should be provided before new investment takes place or commercial changes are considered. This view was broadly supported by GDNs, shippers and NTS customer representatives. One shipper respondent considered that options such as

[39] The UNC OCS process allows GDNs to apply for NTS Exit (Flexibility) Capacity at an NTS/LDZ Offtake in any relevant Gas Year (year Y) or any relevant Gas Year up to year Y+5, by submitting an application to NG NTS during the July Annual Application Window in Gas Year Y-1. NTS Exit (Flexibility) Capacity is not booked by other NTS users.

incentivising flat or profiled entry flows to better match diurnal exit flows; incentivising entry flows closer to the point of higher offtake demand; and utilising gas storage in the area where flexibility was required, could be used as alternatives to investment in pipes or compressors to meet incremental flexibility demand.

1.42. A majority of respondents agreed with our summary of the supply and demand factors which may affect future NTS gas flows, but a number of shippers and GDNs considered that uncertainty surrounding the extent and impact of the changes meant that anticipatory investment carried the risk of being inefficient. These respondents considered that it would be appropriate to undertake further analysis and monitoring of system trends before large investment projects were triggered. One shipper respondent considered that it would be inappropriate to undertake significant investment decisions and/or consider changes to the commercial regime until the conclusions of DECC's Electricity Market Reform (EMR) consultation have been published.

1.43. Shippers and GDNs agreed that although factors such as the move away from UKCS gas in favour of continental gas or LNG, and the impact of renewable generation on CCGT demand, may impact on NTS investment needs, sensitivities around NTS aggregate demand assumptions were also significant. GDN respondents considered that in the medium to long term, energy efficiency measures, and the potential impact, of among other things, biomethane, may cause GDN demand to fall. GDNs considered that the impact of these changes should be modelled in evaluating NTS investment needs.

1.44. Respondents agreed that in the event that the case for new investment to support flexibility needs was proved, it would be appropriate to link the investment to outputs within the RIIOT1 framework, but a majority considered that where possible such investment should be linked to confirmed demand signals. NGG considered that although investment should ideally be linked to user signals, it may not be possible to link all investment to specific outputs. One shipper considered that the investment necessary to cope with changing gas supply flows between days should already have been funded through the revenue drivers NGG obtained in respect of incremental entry capacity released in recent years.

1.45. Respondents agreed that the flexibility indicators developed by NGG in its System Flexibility workshops during 2009 and 2010 could provide useful information about system flexibility trends, but a majority disagreed that the indicators would be capable of identifying future investment needs. NGG considered that the indicators provide a useful view of historical trends but do not provide a forward looking view of future requirements. A majority of GDNs and shippers and a customer representative were concerned that the indicators should not be considered in isolation and that a simple extrapolation of trends should not be used to identify investment needs. Some GDNs considered that the indicators did not provide any location specific information about the availability of capacity and did not appear to take account of diversified demand. One shipper considered that the indicators were of limited use unless analysed in conjunction with information about the actual capability of the NTS to provide flexibility capacity. For these reasons a number of respondents queried the value in placing an obligation on NGG to report on the indicators under the RIIOT1 framework. Other respondents considered that as NGG had already developed the monitoring regime as part of Exit Reform it may not be necessary to introduce a new monitoring obligation under RIIOT1.

1.46. A majority of respondents considered that it is important that efficiency of investment across the NTS/GDN interface is optimised when considering GDN incremental NTS exit (flexibility) capacity needs. To the extent that it is efficient for NGG to invest to meet incremental NTS exit (flexibility) capacity signals from GDNs a majority considered that it would be appropriate for them to do so. NGG considered that if such capacity was made available it would be important for it to carry a user commitment to mitigate the risk of stranded assets. This point was also made by a number of shippers. However, a majority of respondents queried whether there was any evidence that NTS exit (flexibility) capacity was scarce and therefore whether any investment was likely to be required. A number of these respondents considered that historically NTS exit (flexibility) capacity has existed in sufficient and proportionate quantity to NTS exit (flat) capacity and queried why this was likely to change. A shipper and a customer representative noted that despite the NTS experiencing some of the highest peak demand days ever recorded in December 2010, NTS exit (flexibility) capacity obligations were still met and, in fact, the highest flexibility capacity utilisation during December 2010 did not occur on any of the peak demand days. A GDN respondent considered that in evaluating the most efficient way to meet incremental NTS exit (flexibility) capacity requirements, NGG should be obliged to consider System Operator (SO) solutions as well as investment solutions.

1.47. A majority of respondents considered that ideally new investment should be linked to user signals and that where incremental investment costs are incurred these should be targeted at those benefiting from the capacity through the commercial and charging arrangements. However a number of respondents

1.48. identified practical difficulties to achieving this. NGG considered that it may be difficult to map the deep network investment required to provide system flexibility to a specific signal for incremental entry or exit capacity. They also considered that given investment lead times, anticipatory investment may be required to deliver the level of investment which may be required. A majority of respondents agreed with NGG’s view that attributing deep investment costs between entry and exit signals may be difficult. A number of respondents maintained that as flexibility capacity is provided as a consequence of investment for flat capacity, holders of flat capacity should be entitled to an allocation of flexibility capacity and that this should not require the development of a separate flexibility capacity product or flexibility capacity charges. Concern was also expressed in opposition to the possibility of the introduction of a universal flexibility capacity product allocated at auction as considered at the time of Exit Reform. In particular one shipper noted that the complexity and cost associated with the introduction of a commercial product that involved continuous flow monitoring and recording would be detrimental to what is otherwise broadly a daily based gas balancing regime.

Question 2: Do you have views on whether additional transparency and separation

1.49. One response cautioned against transparency and separation where it is at the expense of a close TO/SO relationship.

1.50. Another respondent supported the consideration of greater TO SO alignment and argued that the gas SO capacity release mechanisms and TO capacity provision were as relevant here as the electricity consideration of constraints.

Chapter 5 - Environmental outputs

Question 1: Do you have any views on the environmental outputs outlined?

1.51. One TO thought that the consultation proposals are a good starting point but that there were still a number of issues to be resolved for the final strategy. They noted that there was a significant awareness among stakeholders that a TO's role in the transition is more important than the TO's direct environmental footprint. They also thought more consideration was needed on how to allow internalisation of other environmental costs during the period.

1.52. Another TO thought that output measures should be relevant to stakeholders and be able to be transparently measured and presented. It was important that these are material, proportionate, controllable by the licensee. Incentives applied to outputs must also be material. They also thought it was important to remember that there will be forecast errors and that some network companies are changing dramatically so that historical data might not be appropriate.

1.53. A TO also confirmed they expect to play a key role in transition to low carbon economy. They thought that second order elements, such as losses, should be considered in future price control.

1.54. A large network user thought that environmental outputs should be technology neutral in nature and not favour any particular generation type or energy source. The network user argued that technology specific incentives run the risk of interfering with Government policy, or creating a further cross subsidy that might increase costs to consumers unnecessarily.

1.55. A renewable industry group welcomed the output category for the environmental impacts of TOs. However they noted that the networks role in transporting electricity has a much larger indirect impact on the environment than a direct impact.

Question 2: Are these the appropriate areas to focus on and are there any other areas in which primary outputs and secondary deliverables should be set?

1.56. Two TOs said that the areas are appropriate. Two TOs also said they will consider if there are other network emissions or environmental impacts that should be covered by output when they submit business plan.

1.57. One TO thought that wider reinforcement should be a primary output not a secondary deliverable. They were also keen for a wider measure that captures visual amenity, which is a particular concern to their customers. They thought an output measure in this area would require an allowance.

1.58. Several landscape lobby groups have told us in stakeholder forums and in bilateral discussions that they are concerned that the December proposals did not include a visual amenity output. They strongly encourage the inclusion of willingness to pay analysis to inform the final strategy outputs.

Question 3: Do you agree with the proposed approach to setting environmental incentives?

1.59. Two TOs said they support the proposed approach. One thought it was particularly appropriate when setting financial incentives to consider the level of networks' influence.

1.60. A renewable industry group suggested that the approach to setting outputs should be more focused on the materiality of their impact and potential benefit.

Question 4: Do you have any views on what the TOs 'full role' in a low carbon economy may involve by the year 2020?

1.61. One TO said that they will have a crucial role in transition, encompassing traditional activities and innovative activities. They said it was not feasible to forecast an exhaustive list at this point, which adds weight to a high level output measure as proposed by RenewableUK. A TO said that over RIIO-T1 the focus should be on connections and providing capacity for large renewable generation. In future requirements on TOs may change.

1.62. One TO said that their contribution to national objective of achieving a low carbon economy would be through their core activities and supporting development of low carbon generation and demand side technologies. They said that their supporting role is about facilitating connections, delivering network reinforcements and engaging in research and development activities.

1.63. Two renewable industry groups thought that it was not necessary to define TOs full role as an appropriate incentive would deliver many other behaviours and developments beyond the traditional areas due to the processes of innovation.

Question 5: What role is there for a primary output in RIIO-T1 on TO's contribution to the UK's environmental and energy objectives and what type of incentive would be most effective to drive TOs delivery in this area?

1.64. One TO thought there was clear justification for a broad environmental output with a reputational incentive. Another TO said that there was merit in the RenewableUK proposal but have to recognise the limited scope of network activities to contribute.

1.65. Two renewable industry groups thought it was important to apply a significant financial incentive to a output on TOs contribution. This was needed to drive a paradigm shift. They also thought that a single important output link to the high level environmental goals and an associated incentive is preferable to a number of incentives linked to individual behaviours as there was a much greater risk of missing the targets under the latter approach.

Question 6: Do you have any additional views on RenewableUK's proposal for a specific low carbon economy output including the form and size of such a reward mechanism?

1.66. One TO thought that applying any incentive to such a mechanism would need to prioritise consumer benefit. They also said that it was important that more consideration was given to the interaction with other primary outputs, particularly connections output. They also wanted to see further evidence to support the form and size of any financial reward.

1.67. A consumer group did not agree with the proposal for a broad environmental output and were particularly opposed to applying a financial incentive. Their main concern is that the output is not sufficiently under control of TO, consequently they thought there are risks for potential windfall gains and that consumers pay twice. They thought that most of the important contribution a TO can make to a low carbon economy are the activities captured by the other output categories. They also wanted more information about the consumer benefit from the incentive and questioned whether RenewableUK's modelling was realistic. They also argue that the size of any incentive should reflect the degree to which the output is under the networks control.

1.68. The TOs were open to the introduction of a broad environmental output. One TO thought further clarity was needed on how it would work in practice. Another TO said further clarity was needed on what behaviours the broad measure was trying to incentivise and to what end.

1.69. One renewable industry trade association thought a broad environmental output would provide substantial consumer benefits. If a broad measure was successful in bringing forward the connection of 1GW of renewable energy they estimated this would bring benefits of approximately £500m over RIIO-T1. Other benefits include policy stability, lower renewable energy subsidy, and lower connection costs.

Question 7: Do you have views on the relative roles of the TO and SO in relation gas shrinkage and venting, and how we might align the incentives between the two parties?

1.70. Only one respondent answered this question. They said it that while it would be possible to disaggregate TO and SO activities for gas venting it would be much more difficult for shrinkage. This was because TO investments for shrinkage need to be assessed over the whole life of the asset but incentives are based on short period which means the true value of investment is not assessed correctly. The business plans could be used to set out the approach to optimising investment and shrinkage.

Question 8: What incentives should companies face to manage their carbon footprint?

1.71. Most stakeholders were broadly supportive of a reputational output for business carbon footprint. One TO agreed that the reporting requirements should align with those under the CRC scheme. TOs also agree with the use of a reputational incentive. One TO suggested this could be reviewed at the mid-point review as understanding of companies' footprint improves.

1.72. One renewable industry association thought this output was unnecessary duplication of other regulatory measures eg Carbon Reduction Commitment (CRC) scheme.

Question 9: What incentive should be put on TOs in relation to losses?
Question 10: What are the options to avoid any perverse impacts on network development to connect renewable generation?

1.73. One TO noted it was committed to optimising the level of losses as part of developing and maintaining an economic and efficient network. They thought incentives in price control would have a limited impact because the benefits (and payback) are long lived. The TO said there would be a lot of complexity to establish the losses attributable to TO decisions and to set a baseline. They also said that an improvement in losses coming from TO investment would be small and that it would be better to embed in business plan and perhaps the network development policy.

1.74. Two TOs strongly opposed an output or incentive on losses. They said that transmission losses are a function of the demand and generation backgrounds and that losses will increase as more renewables locate in remote parts of Scotland. They highlighted that a TOs controllability and measurability of losses are constrained by the provision of BETTA. They noted that they currently consider losses as part of their life time cost assessment of investment.

1.75. A renewable industry association said that the carbon impact of losses will be nearly zero by 2030. They were concerned that a losses output could delay connections as losses are mostly easily reduced by not connecting remote renewables.

Question 11: Do you agree with the principle of full internalisation of environmental costs? To what extent should the output for SF_6 move towards this objective?

1.76. TOs broadly supported the SF_6 output and the move towards polluter pays principle in the design of the incentive structure. One TO noted SF_6 assets have various benefits, eg minimise substation footprint, improved safety. It was important that baselines were able to accommodate new switchgear.

1.77. One renewable industry group said that the output should not impact on design choices that were more difficult to obtain planning permission.

Chapter 6 - Customer satisfaction outputs

Question 1: Do you have any views on the primary outputs outlined for customer satisfaction?
Question 2: Are these the appropriate areas to focus on and are there any other areas that should be included?
Question 3: Do you have comments on the proposed approach to setting incentives related to the customer satisfaction outputs?
Question 4: Should the incentives apply to NG both for good performance as SO as well as in its TO role?

1.78. Two non-network respondents expressed support for the proposed customer satisfaction outputs. Two of the TOs were content with the use of customer satisfaction surveys and recognised the need to work with Ofgem to develop these surveys. However, the remaining TO expressed concerns with this approach and had a preference for an approach which would place greater emphasis on stakeholder engagement and TO responses to customer-facing activities eg connections, given the bespoke TO functions that they carry out. A further TO emphasised that care should be taken to ensure that no one customer unduly influenced the results of a survey given the limited number of customers that the TOs have.

1.79. Two TOs noted the difficulties of setting an incentive rate for performance in terms of a customer satisfaction survey. While one offered to provide information to assist this process, the other suggested that more work would be needed before financial incentives could be implemented. One respondent welcomed the proposal to assess TO performance both in terms of the survey score they achieved and their comparative performance as compared with the previous year.

1.80. A number of respondents made reference to the need to consider the roles of various parties when further developing the customer satisfaction survey. Two respondents noted the importance that should be attached to considering the views of all of the TOs customers, with one making specific reference to the need to consider DNOs. A further respondent suggested that the views of groups of network consumers should be weighted to ensure the effectiveness of the survey. One respondent suggested that, in developing the financial incentives, we should have regard to the different roles that NG and the Scottish TOs perform.

1.81. All three TOs supported our proposals related to stakeholder engagement and welcomed the use of a discretionary reward in this area. Of these, one noted that the discretionary reward should be linked to a demonstration of better outcomes as a result of strong customer engagement. One respondent noted that they were keen for the incentive to take effect from 2013/14.

1.82. One TO expressed support for our proposed approach to the handling of complaints and agreed that a complaints handling metric was not appropriate given the differences between transmission and distribution.

Chapter 7 - Conditions for connection

Question 1: Do you have any comment on the key principles we have identified for the delivery for connections?
Question 2: Do you have any comment on the interactions with the other workstreams, in particular Project TransmiT, for electricity transmission connections?
Question 3: Do you have any views on the existing arrangements for gas transmission?
Question 4: Do you consider any specific obligations and /or incentives are required?

1.83. In relation to electricity connections, the TOs responses generally supported focus on timely delivery of connections but while one supported the application of incentives around the current legal obligations, the others highlighted either things outside the TO control involved in connection delivery or that the degree of difference between different connections meant there was no such thing as a typical connection.

1.84. There was general agreement from the TOs that it was too early to judge the success of the revised arrangements including the connect and manage arrangements and that the conclusions in TransmiT might be important in developing the final RIIO-T1 primary outputs and/or incentives.

1.85. On gas connections, the NTS response recognised the absence of definitions of timings but highlighted the consideration of changes through the industry process.

1.86. One other response argued that the existing arrangements did not have sufficient definition of timeframes and processes. It also highlighted the important interaction with the Project TransmiT conclusions.

Chapter 8 - Secondary deliverables - electricity transmission wider works

Question 1: Do you agree that there is a need for secondary deliverables that relate to wider reinforcement work on electricity transmission networks?

1.87. One TO agreed strongly with need for secondary deliverables on wider reinforcement work. One TO agreed with principles set out and that business plans should set out these secondary deliverables. One TO strongly opposed the proposal to categorise reinforcement of the network as a secondary deliverable or subject to a boundary capability incentive scheme. They thought this should be a primary output.

1.88. A renewable industry association did not agree with picking out wider works for a selective incentive. They thought this was only one part of the network that requires investment and a separate incentive may have perverse results in determining how works are classified which may impact on ability to connect. They may be prioritised to the detriment of local or enabling works which could slow connections. They argued that the RenewableUK's proposal would encourage TOs to carry out wider work reinforcements as such wider works would reduce constraints on renewable and low carbon generation outputs.

1.89. One network user said that we should consider if wider works/anticipatory investment would be better specified as a primary output/deliverable.

Question 2: Do you agree with our proposed approach to the specification of these secondary deliverables?

1.90. One TO agreed with using a high level specification such as boundary capability as opposed to specific projects. They thought further work would be needed to get consistent and objective specification. One TO thought it was possible to define secondary deliverables in terms of boundary capability or a project. They said they would prefer TIRG or TII type arrangements. They said it was important that projects being taken forward under a TII type approach have continuity of funding that avoids piecemeal approach of TII.

1.91. Another TO did not understand what is meant by boundary capability and how this would be measured. They noted that many of the reinforcements they expected to make over RIIO-T1 are within conventional planning boundaries. They also said that boundary capability can vary, so was a very subjective specification.

1.92. One large network user was not convinced by a specification using boundary capability. They thought this was too arbitrary/open to interpretation. They argued that there would still be flexibility through alterations to projects.

Question 3: How should we encourage timely delivery and deal with non-delivery?

1.93. One TO agreed with linking financial incentive to delays in delivery and constraint costs and noted that this would also be helped by greater consistency between SO and TO incentives. They said it was inappropriate to claw back the full avoided costs when non-delivery is in interests of customer and questioned whether instead the efficiency incentive rate should apply. They recognised that careful design was needed to avoid TOs putting unnecessary projects into plans. They also highlight that there could be possible impacts of changes in the efficiency incentive rate between price control periods if investment is deferred into the next price control.

1.94. One TO said that regulated network businesses face strong incentives for timely delivery of projects under TIRG and TII as will increase RAV and there is also a reputational driver. They would be concerned if proposed funding arrangements include the period to obtain planning consents, which can be significantly delayed due to outside agencies outside the control of the TO. They thought that exclusions should include provisions for local authority, government consent delays and landowner delays.

1.95. Another TO thought that timely and cost effective delivery is not suited to fixed allowances - whether ex ante or mechanistically fixed to pre-defined outputs.

Question 4: Have we identified appropriate options for bringing flexibility, over the price control period, to the secondary deliverables that TOs should deliver and to the revenues that they receive for this delivery? Which options work best for consumer interest? How would this depend on specific circumstances?

1.96. One TO said that the flex mechanisms should balance between administrative burden, risks of micro-management and high risks for networks and consumers. They thought that: option a could provide benefits for consumers, networks and consumers; option b would lead to more admin burden and risk of micro-management but is probably good for exceptional deliverables, and; option c could bring the most benefit for consumers, minimum admin burden and maximum discretion for networks to innovate.

1.97. One TO did not think there was a strong justification to change the current funding arrangements. They were pleased to see a within period option included in the consultation. The TO prefer option a, based on a deep revenue driver under TPCR4, and option b based on TII. A possible enhancement would be for the future arrangement to provide funding across the full project duration, as under TIRG, rather than one or two years at a time. Given the scale of investment associated with wider system reinforcement projects, they consider it is right for each project to be given detailed regulatory scrutiny of needs case, cost and timing. Although this will increase the administrative burden, higher scrutiny will protect customers.

1.98. One large network user thought it was important that robust arrangements are in place for timely and efficient delivery as these will be large investments. They said they prefer a project specific approach to funding investment taken from an ENSG-type coordinated, strategic framework. They had particular concerns about the impact of flexibility mechanisms on the volatility of tariffs.

Question 5: Do you agree with our plan not to develop proposals for an asset utilisation incentive scheme (option (d)), and to focus, instead, on the other options?

1.99. One TO understood the concerns around risk and costs arising from a utilisation scheme incentive (option d) but think there could be ways to limit risks and said they will consider further as part of development of their well justified business plan.

1.100. One TO agreed that an asset utilisation scheme is inappropriate.

Appendix 2 – Changes to NOMs to reflect our secondary deliverables

1.1. This appendix contains further information on our secondary deliverables for electricity and gas transmission. It highlights the difference between how the businesses currently report under the NOMs and how they will be required to report for RIIO-T1.

Summary of our consultation proposals

1.2. Our December document set out a number of changes to the NOMs to reflect RIIO-T1 secondary deliverables including altering the categories for asset health and criticality and introducing risk indices.

Consultation responses

1.3. Two respondents opposed our proposed changes to the NOMs to reflect RIIO-T1 secondary deliverables.

1.4. One respondent did not support changing the ordering of priority from lowest "1" to highest "4" across asset health, criticality and replacement priorities/risk. It also considered that its current internal definitions of asset health were more appropriate and that these should continue to be mapped to the definitions in the NOMs. Furthermore, it prefers the use of replacement priorities indicating the timescales in which the asset should be replaced rather than a risk index arguing that they are more helpful in communicating how it builds its capital plan. This respondent is also concerned about how easily system availability can be forecasted.

1.5. Another respondent argued that because the asset health definitions were only recently agreed in the NOMs, further changes should not be suggested at this time.

Our strategy decision - electricity transmission

Asset risk (asset health, criticality and replacement priorities)

1.6. Our strategy decision is that we will use asset health, criticality and replacement priorities to capture asset risk.

1.7. An asset health index (HI) provides a framework for collating information on the health (or condition) of network assets and tracking changes in network health over time. We consider it a useful indicator of potential future reliability and safety issues. Asset health, criticality and risk should be used by the TOs to identify capital programs for the forthcoming price control.

1.8. TOs currently report asset health based upon remaining useful life. Assets are placed into one of the categories shown in Table A3.1a. We consider that a HI definition, that reflects only the condition of the asset, is more appropriate assessment of time to replacement, and should only be made after considering an asset's condition and criticality.

Table A3.1a – Current HI – remaining useful life

0-2 years
2-5 years
5-10 years
>10 years

Table A3.1b – Proposed HI definitions for secondary deliverable

HI Band	Definition
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration, requires assessment or monitoring
HI4	Material deterioration, intervention requires consideration
HI5	End of serviceable life, intervention required

1.9. Our strategy decision is that asset health should be defined based on the scale shown in Table 3.1b. We note concerns from two respondents about making changes to the NOMs after they were agreed in 2010, but consider that the commencement of RIIO-T1 provides an important opportunity to specify secondary deliverables. The definitions are the same as those used in the DPCR5 network outputs reporting and will provide consistency across the transmission and distribution networks.[40] The TOs will continue to use their internal asset management processes to assess asset health but will report them under the definitions shown in Table A3.1b.

1.10. Criticality provides a measure of the consequence of failure of an asset. The criticality of an asset is based on system, safety and environmental considerations. These considerations are:

- system criticality is based on the impact of the transmission system not delivering services to customers and any impact on the smooth operation of the UK services and economy
- safety criticality is based upon the risk of direct harm to personnel or the public as a result of asset failure (for example conductor drop, asset fire or explosion)
- environmental criticality is based upon the environmental impact caused by asset unreliability or failure, taking into account the sensitivity of the geographical area local to the asset.

1.11. Based upon the rating for each of these categories, a substation or circuit can then be given an overall criticality rating (see Table A3.2). We consider that the current definitions are suitable for including criticality as a secondary deliverable. In

[40] For further detail see chapter 2 'Instructions for completing network outputs reporting' in the document 'Electricity distribution price control network asset data and performance reporting – Regulatory instructions and guidance: Version 1'
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Electricity%20Distribution%20NADPR%20RIGs.pdf

light of comments received from stakeholders, we have decided to maintain the current criticality rankings in the NOMS (C1 rating be defined as very high criticality and a C4 rating defined as low criticality).

Table A3.2 – Criticality definitions

Rating	Definition
C1	Very high
C2	High
C3	Medium
C4	Low

1.12. Replacement priority indicates how TOs prioritise asset replacement decisions. It is a function of the asset health and the criticality of the substation or circuit where the asset is located.

1.13. Replacement priority is currently measured in terms of remaining years of use (see Table A3.3a). We have considered comments from stakeholders and decided to maintain the replacement priorities used in the NOMs for categorising the level of risk of the network (with a 0-2 years replacement priority being the highest level of risk and a 10+ years replacement priority being the lowest level of risk). We note that the businesses have developed detailed methodologies for identifying these priorities and that these definitions are helpful in communicating how they build their capital plans. Maintaining these definitions will also provide continuity with information captured to date under the NOMs. It is important to note that replacement priorities provide information on the relative rankings of assets within a particular asset class in terms of risk and relative need for replacement. Once replacement priorities are identified, the businesses then consider outages, resources, alignment with system drivers and scheme bundling to develop their capital plans. We also note that it is an important part of the company's management decision to decide where to justify the line in terms of what assets should be replaced, maintained or refurbished. For example, the fact that an asset has been categorised in the 2-5 year replacement priority is indicative and does not mean it has to be replaced in that time period.

Table A3.3a Replacement priority

No. of years before replacement
0-2 years
2-5 years
5-10 years
>10 years

1.14. TOs can also provide further information within the commentary to explain the reasons behind their replacement decisions. TOs should articulate the case for spending a marginal pound on one asset over another and include information on the particular risk trade-offs made between the different asset categories.

1.15. As discussed in Chapter 5, we maintain our view that, in the long term, the TOs should pursue a system-wide risk assessment to justify investments in assets that impact on the reliability and safety of the network or on the environment.

Average circuit unreliability (ACU) and system unavailability

1.16. We have decided to use ACU as a secondary deliverable to ensure that the primary output, ENS, will continue to be delivered in future price controls. All TOs should collect this on a monthly basis and report this at asset type level.

1.17. ACU provides data to show the impact of asset unreliability on the network which could be an indicator of the decline of overall asset health.

1.18. ACU measures the percentage of hours the network is unavailable due to outages (both planned and unplanned) caused by functional failures. Functional failures are defined as unreliability events which result in unavailability of the network due to outages which cannot be deferred until the next planned intervention and include:

- enforced unreliability outages taken at less than 24 hours notice (unplanned unavailability)
- planned unreliability outages taken after 24 hours notice.

1.19. NGET report the total ACU figure for all assets and provide this figure broken down for each month of the reporting year. NGET also captures this data at asset type level (transformers, switchgear, overhead lines, underground cables, protection and control). SHETL and SPTL do not currently capture the information at this level. We have decided that all companies report ACU at total asset and individual asset level in future. We will also require that the monthly breakdown is provided.

1.20. System unavailability is a measure of the percentage amount of time for which circuits are unavailable. We consider it a useful secondary deliverable as it shows the impact on the network from all types of outages. System unavailability is derived from:

- system unavailability due to planned user connection outages (planned outage where more than 24 hours notice given due to user connection issues)
- system unavailability due to planned construction outages (planned outage where more than 24 hours notice given due to construction issues)
- system unavailability due to planned maintenance outages (more than 24 hours notice given due to maintenance issues, excluding those due to reliability).
- ACU (see below).

1.21. We have decided that TOs forecast this system unavailability and ACU for one year ahead, rather than for the duration of the price control period. This is because many outages are caused by weather events and this makes it difficult to forecast accurately eight years ahead.

1.22. We will also capture system unavailability due to planned non-reliability outages as a secondary deliverable. This is consistent with our proposed primary output, ENS, which also includes planned outages. System unavailability should be monitored as a means of assessing trends that may impact on likely future performance of the primary output.

Faults and failures

1.23. We will also use faults and failures as secondary deliverables. A fault is an event which causes plant to be automatically disconnected from the HV system for investigation and further action if necessary.

1.24. TOs report the number of faults for:

- weather related trips and delayed auto-reclose (DAR) faults
- non-weather related trips
- faults requiring an outage of more than three hours.

1.25. A failure usually indicates where an asset needs replacing. Failures are defined specifically for each asset type.

1.26. The number of assets which have had faults or failures is reported under Standard Licence Condition B17 Network Output Measures. This data is not currently forecast. We do not propose to change this as the low volumes involved would make this difficult to forecast meaningfully.

Our strategy decision - gas transmission

1.27. An asset health index (HI) provides a framework for collating information on the health (or condition) of network assets and tracking changes in network health over time. We consider it a useful indicator of potential future reliability and safety issues. Asset health, criticality and risk should be used by NGG to identify capital programs for the forthcoming price control

1.28. NGG currently reports on measures of asset health and criticality under Licence Condition C13 Network Output Measures (NOMs). However, we have decided that these measures be further developed for RIIO-T1 to provide a more consistent framework to that outlined for electricity transmission (and developed as part of DPCR5).

1.29. The NOMs currently categorise NGG's assets into five primary asset groups based on the key reason for the asset. These are entry points, exit points, compressors, pipelines and multi-junctions. Each primary asset is supported by secondary assets that are installed to protect/minimise the risk of principle components failing.[41] Secondary assets are categorised into 47 groups, with some secondary assets supporting more than one primary asset.

1.30. Asset condition is currently reported for each of the 47 secondary asset groups based on a 'time frame on work required' (see Table 3.4a). Secondary assets are also assigned a criticality profile and criticality level. A risk index is not currently reported.

1.31. As noted for electricity transmission, our strategy decision is that asset health should be defined purely on the basis of asset condition. Our definitions for asset health are shown in Table 3.4b.

Table 3.4a – Current HI – remaining useful life

0-2 years
2-5 years
5-10 years
>10 years

Table 3.4b –HI definitions for secondary deliverable

HI Band	Definition
HI1	New or as new
HI2	Good or serviceable condition
HI3	Deterioration, requires assessment or monitoring
HI4	Material deterioration, intervention requires consideration
HI5	End of serviceable life, intervention required

1.32. We also consider that the criticality framework used in the current NOMs should be further developed. Our decision is that a measure of criticality that is consistent with electricity transmission needs to be applied. We note that reporting on this basis for 47 categories is likely to be disproportionate and we are looking for NGG to define between 10 and 15 categories that capture the majority of the associated investment.

1.33. A measure of criticality should be capable of ranking identical assets on different parts of the network. Our view is that this should be based on the reliability, safety and environmental consequences of asset failure. The criticality of individual assets should be a function of impact of failure of the secondary asset as well as the subsequent impact on the primary asset and the network as a whole. We will continue to work with NGG to agree thresholds for safety, reliability and environmental criticality prior to the submission of their business plans.

1.34. The measure of criticality should take into account the differences in the criticality of the secondary asset as well as the criticality of the primary asset where relevant (for example the failure of two identical assets installed as part of different primary assets may have different impacts on the reliability of the network and thus we would expect to have different criticality ratings to reflect this).

[41] NGG submission to reliability and safety working group, 7 September 2010

1.35. In other cases (for example remote isolation valves) the criticality of the secondary asset may be the same regardless of where it is situated. In these cases we would still require NGG to demonstrate how investment decisions are made when spending a marginal pound.

1.36. Our criticality definitions are shown in Table 3.5.

Table 3.5 – Criticality definitions

Rating	Definition
C1	Low
C2	Medium
C3	High
C4	Very high

1.37. Based on the asset health and criticality of an asset, NGG should then develop a replacement priorities as shown in Table 3.6a.

Table 3.6a – Replacement priorities

0-2 years
2-5 years
5-10 years
>10 years