NECEC 1-12

Request:

The National Grid website contains a discussion of the regulatory regime used by Ofgem to regulate National Grid UK. The Company's compensation is determined in part by its production of seven outputs, three of which are as quoted:

v. customer satisfaction
vi. timely connections
vii. connection works and wider works

See: https://www.nationalgrid.com/uk/about-grid/how-we-are-regulated/riio-regulatory-framework

a. Please describe the "consultation process" used by the regulator to assess the Company's performance on these output measures.

b. Is it correct to say that Ofgem "surveys" the customers of each Transmission Grid Operator as part of the assessment of each operator's performance?"

c. Please provide copies of the most recently-used assessment forms ("response templates") used by Ofgem to gather customers' opinions about the performance of transmission grid operators.

d. Does Ofgem use a similar regulatory process for the evaluation of the performance on interconnection of Distribution Network Operators (DNOs)?

e. Would National Grid support the use of surveys of customers and interconnecting parties as part of the assessment of its performance on Network Support Services and Distributed Energy Resources? If no, why not?

Response:

a. Before the price control period started in 2013, Ofgem ran a public consultation process when deciding on incentives and outputs ahead of defining the RIIO-T1 price control outputs. For National Grid Electricity Transmission, the output measures and incentives are defined in Chapter 2 of the RIIO-T1 Initial Proposals attached herein as Attachment NECEC 1-12-1. All interested parties had the chance to respond to this consultation and National Grid constructed its business plan in consultation with its stakeholders. The outputs and incentives were then set by the Final Proposals, which were provided in Attachment NECEC 1-9. Once the price control period starts, the application of the incentives is a mechanistic process with no direct consultation. The Transmission Owners produce a comprehensive Regulatory Reporting Pack reporting performance on outputs and incentives for Ofgem, attached herein as Attachment NECEC 1-12-2. Ofgem then assesses performance, asking National Grid supplementary questions as required, and then adjustments to allowed revenues are automatically triggered based on performance against the agreed targets.

b. No, Ofgem does not carry out any surveys assessing performance itself. Rather, the Transmission Owner is required, by Ofgem, to engage an external survey company to conduct the Customer Satisfaction Survey and Stakeholder Satisfaction Survey. These surveys are referred to in the RIIO-T1 final proposals (please refer to Attachment NECEC 1-9), where they are part of an incentive scheme that rewards Transmission Owners for good customer and stakeholder satisfaction.

Customers are those who pay the Company (*e.g.*, power stations, distribution network operators), and stakeholders are those who are affected by the Company's activities (not including those who are already counted as customers), which could include local residents and consumer groups. Domestic consumers (*i.e.*, households) would not be surveyed on the transmission operator's performance.

c. Please see Attachment NECEC 1-12-3 and Attachment NECEC 1-12-4 for the latest available copies of surveys conducted by an external party to stakeholders and customers.

d. Ofgem uses a similar regulatory process for evaluating the performance of Transmission Operators (TOs) and Distribution Network Operators (DNOs) in the RIIO-T1 and RIIO-ED1 price controls, both of which evaluate performance on connections as an output. The metrics and measurements differ, however, between TOs and DNOs. The measures for connections for TOs and DNOs are:

Transmission	Distribution
Timely connections • Send customer offers within 90 days Connection works and wider works • Connection of new generation (GW) • Construction of new overhead line to accommodate new customers (km OHL) • Incremental Wider Works to strengthen specific boundaries (GW) • Timely delivery standards for Baseline Wider Works and Strategic Wider Works	Connections • Guaranteed Standards of Performance (minimum service level) • Customer satisfaction survey (for minor connections customers) • Time to Connect incentive (for minor connections customers) • Incentive on Connections Engagement (for major connections customers)

Prepared by or under the supervision of: Kayte O'Neill

For more detail on the Connections metrics, please refer to the RIIO ET1 2016-2017 Report for Transmission, included herein as Attachment NECEC 1-12-2 and the Strategy decision for the RIIO ED1 electricity distribution price control, included herein as Attachment NECEC 1-12-5.

e. The Company believes that objective, observable measures, such as those included in the tariff requirements and proposed by the Company as performance incentive mechanisms (with targets exceeding the tariff requirements) will most efficiently and accurately measure the Company's progress and performance in delivering on Rhode Island's clean energy goals.

ofgem Promoting choice and value
for all gas and electricity customers

RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas

Initial Proposals – Outputs, incentives and innovation Supporting Document

Reference: 104/12

Publication date: 27 July 2012

Response deadline: 21 September 2012

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Overview:

This Supporting Document sets out further detail on our Initial Proposals for the transmission price control for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT) from 1 April 2013 to 31 March 2021. This document does not change the output obligations for SP Transmission Ltd (SPTL) or Scottish Hydro-Electric Transmission Ltd (SHETL) set out in their April 2012 Final Proposals. However, it does update on progress on ongoing work referred to in that Final Proposals document.

The document includes further detail on the Initial Proposals in relation to the outputs that both NGET and NGGT will be required to deliver and the incentives that will apply around delivery in RIIO-T1. It also includes our Initial Proposals on the arrangements to encourage innovation by NGET and NGGT.

Alongside the document, we are publishing two other Supporting Documents focusing on 'Cost assessment and uncertainty' and 'Finance'.

The document and the other supporting documents are aimed at those seeking a detailed understanding of the Initial Proposals. Stakeholders wanting a more high-level overview should refer to the Initial Proposals Overview Document.

Associated documents

Overview Document

RIIO-T1: initial Proposals for NGET and NGGT - Overview Document

Supporting Documents

RIIO-T1: Initial Proposals for NGET and NGGT – Cost assessment and uncertainty

RIIO-T1: Initial Proposals for NGGT and NGET – Finance

Associated Documents

RIIO-T1/GD1: Initial Proposals – Real price effects and ongoing efficiency appendix

RIIO-T1: Initial Proposals for NGGT and NGET – Impact Assessment

RIIO–T1/GD1: Financial model

RIIO-T1 Stage 4 - National Grid System Operator Electricity and Gas Capex and Opex Initial Assessment – Summary Report

RIIO-T1 SUMMARY REPORT – GAS A report to the Office of Gas and Electricity Markets July 2012

RIIO-T1 Stage 4 NGET Final Assessment – A report for Ofgem

Licence consultation documents

RIIO-T1 and RIIO-GD1: Draft licence conditions – First informal licence drafting consultation

Supporting Document 1: Draft RIIO-T1 Electricity Transmission licence changes

Supporting Document 2: Draft RIIO-T1 Gas Transmission licence changes

Supporting Document 4: Response template for RIIO-T1 & GD1-First licence drafting consultation

RIIO ET1 Price Control Financial Handbook

RIIO GT1 Price Control Financial Handbook

Other documents

RIIO-T1: Initial Proposals for National Grid Electricity Transmission plc and National Grid Gas plc - Headlines

Glossary for all the RIIO-T1 and RIIO-GD1 documents

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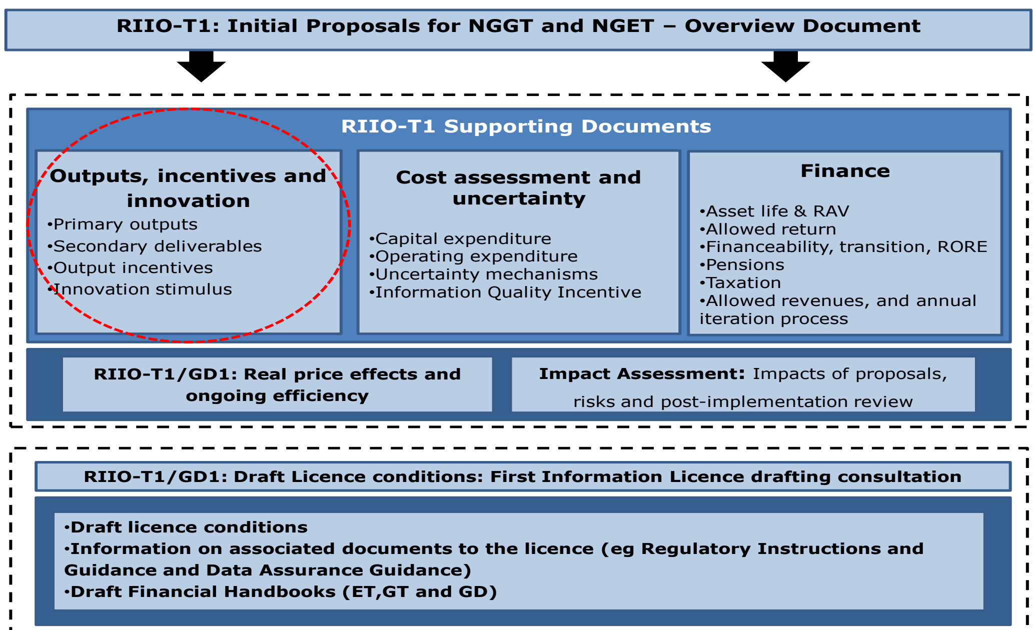
1. Introduction

Chapter Summary

This chapter explains the structure and purpose of the document and sets out the context of the outputs and incentives described within these Initial Proposals.



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

Purpose of this document

1.1. This document sets out, for consultation, our Initial Proposals for the outputs to be delivered and the associated incentives that will apply around delivery for National Grid Electricity Transmission (NGET) and National Grid Gas (NGGT) for the next transmission price control, RIIO-T1. This price control will cover the eight-year period from 1 April 2013 to 31 March 2021. This document also outlines the proposed arrangements to support innovation by the companies.

1.2. The document provides further detail to support the Initial Proposals Overview Document ("Overview Document"). Alongside this document, we are publishing two other Supporting Documents on costs and uncertainty ("Cost assessment and uncertainty Supporting Document") and financial issues ("Finance Supporting Document"). These Supporting Documents are aimed primarily at network companies, investors and those who require a more in-depth understanding of the proposals.

1.3. The document does not set out Initial Proposals for the outputs to be delivered by SP Transmission Ltd (SPTL) or Scottish Hydro Electric Transmission Ltd (SHETL). This is because the price control packages put forward by SPTL and SHETL were subject to "fast-tracking".[1] We published Initial Proposals for those companies in February 2012. We published Final Proposals[2] for those companies in April 2012. Two aspects of the outputs and incentives framework where we required further work from SPTL and SHETL, as well as from NGET and NGGT, were:

- the SO:TO alignment work involving development of a network access (formerly referred to as availability) policy
- the work to implement the customer/stakeholder satisfaction output.

1.4. We provide an update on the progress made to date by the companies in these areas in Appendix 1 of this document.

Requirement to deliver outputs

1.5. RIIO is an outputs-led framework. It is important that throughout the RIIO-T1 period, the transmission owners (TOs) understand what they are expected to deliver and are held to account for delivery.

1.6. Our March 2011 Strategy Document[3] ("Strategy Document") set out the outputs we expected the TOs to deliver in the RIIO-T1 period. We developed these through written consultation and stakeholder workshops.

1.7. The outputs set out in the Strategy Document provided the context for NGET's and NGGT's July 2011 and March 2012 updated business plans. We explicitly stated that TOs could propose departures from our Strategy Document on particular outputs. In such cases, the TO would be required to describe its proposed approach clearly. It also needed to justify why the alternative was likely to improve expected outcomes for consumers compared to the position set out in our Strategy Document.

Assessing performance against outputs

1.8. Under RIIO, we will generally consider a TO's performance against its outputs on an annual basis. We will set out in our Regulatory Instructions and Guidance (RIGs) information requirements and monitoring arrangements. We intend to publish the RIGs by the end of 2012.

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[1] Where business plans are of sufficient quality, fast-tracking provides a process whereby we can reach early settlement of a company's price controls, ie their business plans may be "fast-tracked".
[2] RIIO-T1: Final proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd. This document is available on our website at http://www.ofgem.gov.uk/NETWORKS/TRANS/PRICECONTROLS/RIIO-T1/CONRES/Documents1/SPTSHETLFP.pdf.
[3] 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

1.9. In RIIO, non-delivery of these outputs is not just a matter for the applicable financial incentives. The TOs are also accountable for their delivery through the licence. We may take enforcement action where there is material delivery failure. This means that even where there is a limit to the financial penalty associated with poor delivery, for example in the case of reliability, the licence enforcement process remains as a backstop. This provides additional protection for consumers in the case of significant underperformance on output delivery. Where both enforcement and financial incentives were applicable, the enforcement decision would take account of the financial incentives applied.

Setting the level of incentives

1.10. Under RIIO it is not possible to set out the actual level and profile of annual allowed revenue that NGET and NGGT can collect. This is due, in part, to within period revenue flexing mechanisms that will adjust the opening base revenue allowances. Examples of mechanisms that can alter allowed revenue over the price control period include the uncertainty mechanisms, the Strategic Wider Works (SWW) mechanism and the application of the efficiency incentive rate.

1.11. In order to maintain strong output incentives we intend to make sure that where caps and collars apply to these, they do not just reflect the starting position on revenue called the 'opening base revenue allowance'. Instead, we propose that they adjust in response to ongoing, but uncertain, changes in revenue in order to better reflect the true change in network total expenditure (totex) and other in-period adjustments over the price control period.

1.12. To do this we propose that the maximum caps and collars will be linked to a combination of the opening base revenue allowance plus within-period adjustments captured through annual iteration of the financial model and for NGET the revenue from Transmission Investment in Renewable Generation (TIRG)[4]. This will include all additional totex that is triggered during the RIIO-T1 price control period.

Structure of this document

1.13. The remainder of this document is structured as follows:

- Chapter 2 sets out the proposed outputs and incentives package for NGET.
- Chapter 3 sets out the proposed outputs and incentives package for NGGT.
- Chapter 4 sets out the proposed arrangement that will apply to encourage NGET and NGGT to innovate and to meet the requirements of their innovation strategies.
- Appendix 1 updates on progress made by NGET, NGGT and by SPTL and SHETL on work to implement the customer/stakeholder satisfaction output and to develop network access policies.

[4] TIRG is a mechanism designed to fund transmission projects specific to connecting renewable generation outside of the price control allowance to minimise delays. TIRG is comprised of four projects: Beauly Denny, Sloy, South West Scotland and the Anglo Scottish Interconnector.

1.14. Alongside this document, we have also published an initial consultation on licence drafting for all transmission companies. In final form, many of the draft conditions will implement the outputs and incentives discussed in this document. We are also publishing an impact assessment, which will include our understanding of the effect of these outputs and incentives along with the rest of the RIIO-T1 package.

1.15. All monetary values in this document are in 2009-10 prices unless otherwise stated.

2. NGET: Outputs and incentives

Chapter Summary

This chapter sets out the outputs that we propose NGET should deliver and associated incentives that would apply around delivery over the RIIO-T1 period. Each section starts with our Initial Proposals. We then describe our reasons for these including our assessment of NGET's business plans. We highlight where our Initial Proposals directly reflect the proposals in NGET's business plan and where they differ.

Question 1: Do you have any comments on our Initial Proposals on NGET's output and incentives?

Question 2: Do you have any views on our Initial Proposal on setting an expenditure cap for the start of RIIO-T1 in relation to addressing the visual amenity impacts of existing infrastructure in designated areas?

Introduction

2.1. This chapter sets out our Initial Proposals for the outputs to be delivered, and the associated incentives that would apply around delivery, in relation to NGET during RIIO-T1. The chapter takes each category of output in turn.

2.2. Appendix 1 to this document provides further details on two areas of proposed outputs where further development work continues. This work is seeking to implement the output and incentive principles set out here and, where appropriate, referring back to our Strategy Document. It relates to:

- customer and stakeholder satisfaction outputs
- availability outputs focused on the development of network access policies (NAPs).

Outputs we are requiring NGET to deliver over RIIO-T1

Safety

Our Initial Proposals

2.3. Our Initial Proposals on this output are that NGET needs to be compliant with its legal safety requirements. These are requirements monitored by the Health and Safety Executive (HSE) as the safety regulator.

2.4. In addition, our Initial Proposals also require NGET to maintain and report annually on a suite of measures on criticality, replacement priorities (or risk), system unavailability and on average circuit unreliability (ACU), faults and failures. These measures inform both the safety and reliability of NGET's network. The measures are important despite not involving direct financial incentives. Performance against them informs us about the continued and sustainable delivery of a safe and reliable network. This is both to the end of the RIIO-T1 period and into the subsequent price control period.

Our assessment

2.5. Our Initial Proposal is consistent with NGET's proposals in its business plan which, in turn, is consistent with our strategy decision in this area.

Reliability

Our Initial Proposals

2.6. We propose that NGET be held to account for delivering an output on the level of energy not supplied (ENS) each year. The target level is 316MWh per annum during the RIIO-T1 period. The incentive rate is £16,000 per MWh with the company gaining reward for delivering ENS less than that and suffering penalty for each MWh worse than the 316MWh target. We will maintain the level of the incentive rate in real terms for the period. The incentive has a natural cap as NGET cannot reduce ENS below zero. We will limit the downside risk from this incentive by applying a 3 per cent collar. This is consistent with our assessment of the risk of NGET's overall package.

2.7. The ENS incentive would be subject to a number of exclusions. We are proposing to completely exclude ENS related to customer-choice connections and events lasting less than or equal to three minutes. In other cases such as extreme weather events, it will be a matter for the Authority to understand the specific circumstances of the case before deciding whether to exclude any ENS from this incentive.

2.8. As in the section above on Safety outputs, our Initial Proposals also require NGET to maintain and report on a series of measures on criticality, replacement priorities (or risk), system unavailability and on average circuit unreliability (ACU), faults and failures.

Our assessment

2.9. NGET's business plan proposal accepted our strategy decision that we relate the output for reliability to a target level of ENS. It also incorporated the proposed 3 per cent collar. It proposes the same level of incentive rate as SHETL and SPTL, ie £16,000 per MWh, which is within our range in our strategy decision (£4,300 - £22,000 per MWh).

2.10. NGET proposed a target level of 316MWh per annum for the RIIO-T1 period. This is a slightly higher rate of ENS than our final proposals for either SHETL or SPTL. However, given NGET's network is more meshed and extensive this is not surprising. Having reviewed the modelling underpinning its proposal we are satisfied that NGET's proposed target is appropriate in that it is realistic but challenging.

2.11. We also welcome NGET's proposal, consistent with our strategy decision, to maintain and report on the series of measures to provide useful leading information on how NGET is managing its network. We accept the approach to measurement that NGET proposes.

Availability: Network Access and SO:TO interaction

Our Initial Proposals

2.12. Our Initial Proposals are for NGET to produce and maintain a Network Access Policy (NAP). This should contribute to better SO:TO interaction and cooperation in short and long-term network planning.

2.13. We propose that NGET continues to engage with SPTL and SHETL in the development and maintenance of their respective NAPs. This is in advance of the start of the RIIO-T1 control period. Ongoing engagement will also be necessary during the period if they need to update the NAP for changes in circumstances or lessons learned.

2.14. Our separate SO incentives from 2013 document is being published today discusses the external incentives for NGET as SO.[5]

Our assessment

2.15. Throughout both RIIO-T1 and the SO incentives from 2013 projects we have worked to make sure that we align the incentives facing TOs and the SO where choices can be made across the two functions that minimise overall costs to consumers or where the costs caused by one can affect the other. The above NAP development is the central area of interaction on the electricity side though we have also developed other proposals assessing the combined TO and SO impact eg our proposals in relation to transmission losses.

2.16. Appendix 1 provides the context of, and an update on, progress with NAP development (including the interaction with the SO incentives from 2013 work).

[5] Ofgem: System Operator incentive schemes from 2013: initial proposals, 27 July 2012. This is available on our website at
http://www.ofgem.gov.uk/Markets/WhlMkts/EffSystemOps/SystOpIncent/Documents1/IP%SO%2013.pdf

2.17. We value the contribution of all parties to the development of the NAPs. We recognise the different circumstance for NGET. This is because NGET, as the one company performing both SO and TO roles, faces incentives from the costs and benefits associated with both network constraints and TO costs and benefits. We continue to see value in NGET producing its own NAP. This should provide transparency about the existing interactions and potentially demonstrate best practice that might be adopted in the more complex situation where separate TOs do not face the combined effect of direct TO and SO incentives. NGET has already provided information and challenge to SHETL and SPTL in development of their NAPs and a progress update is included in Appendix 1 of this document.

Customer Satisfaction

Our Initial Proposals

2.18. Our Initial Proposals are that NGET should have a financial incentive informed directly by the results of a survey and other supporting information. The survey should clearly highlight the distinction between NGET's activities and other roles that may be carried out by it or other companies. This will have the limits of plus or minus 1 per cent of the particular year's allowed revenue. Work is progressing on details of how this incentive will be implemented (further detail on progress is included in Appendix 1). A further part of our Initial Proposals in this area is provision for a possible reward for using ongoing stakeholder engagement to generate an exceptional outcome. See Appendix 1 for more details of work on this to date and see the initial draft of the associated licence drafting for further details on the guidance we are developing to support this incentive.

Our assessment

2.19. NGET has some experience of carrying out customer surveys and has done a lot of work through its stakeholder engagement to understand how it can extend this to all stakeholders and make sure that its coverage is comprehensive (in activity) and that the survey seeks views from stakeholders impacted by all its activities. NGET proposes that it will carry out a survey across all stakeholders reflecting the activities that it carries out as TO and SO.

2.20. It accepts the strategy decision to apply a financial incentive with the parameters identified above. However, work to date on developing the survey and designing how the incentives will work in practice suggests that modifying the incentive in the light of supporting information on performance might be a part of the approach.

2.21. In addition, NGET accepts the discretionary reward for delivering exceptional results through effective stakeholder engagement. This could be as much as 0.5 per cent of annual allowed revenue. We have been working with NGET and other TOs to produce guidance to assist them in understanding the process and assessment criteria. We will consult on this in our second informal consultation on licence modifications in Autumn with an aim of publishing guidance with the December 2012

Final Proposals. However, we anticipate updating this for 1 April 2014 incorporating lessons learned in both transmission and gas distribution up to that time.

Connections

Our Initial Proposal

2.22. We propose that the connections output for NGET should be the timely meeting of its existing licence obligations in relation to delivering connections. Consistent with our Strategy Document, given the importance, in electricity transmission, of timely connections with respect to the delivery of a sustainable energy sector, we include scope for a possible financial penalty equivalent to up to 0.5% of allowed base revenue.

2.23. To put the importance of this output in context, we set out the Best View6 for new transmission connected generation capacity in England and Wales over RIIO-T1 in Table 2.1. Please see the Cost assessment and uncertainty Supporting Document for further details on our efficiency assessment and risk sharing arrangements

Table 2.1 New transmission connected generation capacity over RIIO-T1

New Generation Connections Capacity	Baseline funding	Uncertainty Mechanism funding	Best View total expenditure
	(£m)	(£m)	(£m)
33,000MW	794.3	220.5	1,014.8

Our assessment

2.24. NGET accepted this aspect of our strategy decision in its business plan. It has sought revenue to reflect that position. We are satisfied with NGET's proposals in this area and these will form the basis of the Initial Proposals for its connections output.

2.25. These obligations are already present in the licence. However, we have been working with TOs on drafting related to the financial penalty. We have not included a draft condition and intend to work further on this to inform our Autumn consultation on licence conditions.

Environmental outputs

<u>Sulphur hexafluoride (SF_6) emissions</u>

Our Initial Proposals

[6] 'Best View' is the expenditure that we consider the licensees will need to deliver the outputs under the central scenario . It comprises 'baseline' and 'uncertainty mechanism' funding.

2.26. We propose to adopt NGET's business plan proposition that all new assets using SF_6 gas such as switchgear are commissioned with a target leakage rate of 0.5 per cent per annum. This leakage rate is consistent with the best practice set by the International Electrotechnology Commission standard 62271-203 for high voltage switchgear.[7]

2.27. Similar to NGET's business plan, we also propose that the TO's baseline target for SF_6 emissions is calculated annually. However, we propose that this is calculated by adding 0.5 per cent leakage from the inventory of new SF_6 assets installed over the year to the actual emissions for the previous year. The emissions from new SF_6 assets would be added proportionately based on the amount of time they were commissioned during the year.

2.28. As set out in our Strategy Document differences between actual SF_6 emissions and the calculated annual baseline will be subject to a symmetrical marginal incentive based on the non-traded carbon price.

Our assessment

2.29. NGET significantly improved its approach to SF_6 emissions in its March 2012 business plan compared to its July 2011 plan. In particular, NGET provided more context on the operational issues it faces around SF_6 equipment, how SF_6 emissions relate to its wider group carbon goals and how its proposals sit in relation to best practice.

2.30. The most significant revision NGET made in its re-submission is to halve the proposed leakage rate of new SF_6 assets installed on its system from 1 per cent to 0.5 per cent. Given NGET forecasts an increase in the population of both transformers and switchgear, procurement of equipment with a smaller leakage rate would represent a gain, relative to its July plan, in terms of NGET's environmental performance over the price control.

2.31. Although NGET forecast the leakage rate of SF_6 emissions from its network will be around 1.5 per cent at the end of RIIO-T1, down from 1.86 per cent at beginning of period, emissions in absolute terms will increase. As a result, SF_6 emissions will continue to be the largest contributor to NGET's business carbon footprint and will cause a 16 per cent increase overall in the business' carbon dioxide equivalent emissions at the end of RIIO-T1. Therefore we consider NGET's focus on improving its control technologies for SF_6 emissions in its innovation strategy is an appropriate response.

2.32. In our Initial Proposals we have adopted several of NGET's propositions in relation to SF_6. However, we do not believe that its proposal to adjust the annual baseline target for a marginal increase in leakage from its existing inventory would

[7] The International Electrotechnical Commission prepares and publishes International Standards for all electrical, electronic and related technologies collectively known as "electrotechnology". See http://www.iec.ch/.

provide the right incentives. We note that since the start of the last price control, TPCR4, NGET has increased its inventory of SF_6 by more than 50 per cent. With a large proportion of relatively new assets in its existing inventory, we consider that the risk of deterioration is more likely in NGET's older assets and could amount to relatively significant leakage events unless action is taken. We believe that adjusting NGET's baseline for an average marginal increase in leakage from NGET's total existing inventory each year would weaken the incentives on NGET to improve its SF_6 leakage detection and capture technologies. Given the increasing trajectory of SF_6 inventories in transmission for the foreseeable future, it is important that NGET continues to improve this operational capability. We propose therefore to set the NGET's baseline target without any adjustment for deteriorating assets.

<u>Business Carbon Footprint</u>

Our Initial Proposals

2.33. In line with our strategy decision we propose that NGET reports annually to stakeholders on its scope 1 and scope 2 greenhouse gas (GHG) or carbon dioxide equivalent emissions at business level throughout the RIIO-T1 period.[8] We note that NGET set out similar commitments in its March business plan.

2.34. NGET will face reputational incentives only on its business carbon footprint (BCF) reporting.

Our assessment

2.35. This is another aspect of NGET's business plan that has significantly improved compared to its July 2011 plan. For example, NGET clarified that it has made significant progress in its group's climate change target for a 45 per cent reduction in scope 1 and 2 emissions by 2020 compared to the 1990 baseline, having achieved a 34 per cent reduction as at 2010/11. It also provided evidence that it is taking a proactive stance in reviewing its scope 3 emissions through taking part in a pilot for the Greenhouse Gas Protocol, Corporate Value Chain (Scope 3) Accounting and Reporting Standard.

2.36. We recognise that NGET faces a challenge in playing a central role in facilitating more low carbon sources of energy over RIIO-T1 and in doing so might place upward pressure on its own BCF. Nonetheless we believe NGET has a valuable opportunity to make cost effective emission reductions. For example, given the size of its investment programme over RIIO-T1 NGET could bring a large influence to bear on manufacturers and the supply chain generally through its procurement policies to reduce the embedded carbon content and drive improvements in the environmental performance of equipment.

[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.

2.37. We reiterate our position that NGET is required to produce its BCF at the business level to enable accurate reporting on its carbon equivalent GHG emissions from the transmission business.

2.38. We also note that our assessment of NGET's BCF will also form part of the Environmental Discretionary Reward (EDR) scheme. The EDR scheme will enable Ofgem to compare the performance of each TO in producing and publishing business level footprints. We expect this will act as a strong reputational driver to performance in this area in addition to the potential to receive a reward under the EDR.

Transmission Losses

Our Initial Proposals

2.39. In line with our strategy decision we propose to set reputational incentives on NGET in relation to its overall approach to contributing to fewer transmission losses where it can do so and provide long term value to consumers.

2.40. We propose that NGET should publish its strategy for transmission losses and report to stakeholders annually on its progress in implementing its strategy. We propose that this includes an estimate of the impact this has had on transmission losses in its transmission area.

Our assessment

2.41. Similar to SF_6 and BCF, NGET's March 2012 business plan on transmission losses set out a lot more context and substance compared to its July 2011 plan. NGET included a useful illustration based on three different generation scenarios to show how the potential level of transmission losses over RIIO-T1 will depend largely on the growth and location of generation, as well as investment in new transmission capability.

2.42. As part of its business plan response to transmission losses, NGET provided a case study on its tender evaluation processes for new transformers. While this information was useful it fell short of providing an integrated account of how it has reviewed the opportunities to contribute to fewer transmission losses and the cost effective opportunities it proposed to take forward in its RIIO-T1 business plan.

Visual amenity

2.43. Our Initial Proposals in respect of addressing visual amenity issues arising from transmission assets are twofold. The first proposal is that NGET efficiently meet the planning requirements for new infrastructure. Our second proposal is that NGET mitigates the visual amenity impacts of existing infrastructure when it is located in National Parks and Areas of Outstanding Natural Beauty ('designated areas').

Our Initial Proposals – new transmission infrastructure

2.44. We propose NGET efficiently addresses the visual amenity impacts of new transmission infrastructure where necessary to obtain development consent from the Secretary of State. This is consistent with NGET's requirements as a proposer of potential new developments under the Planning Act 2008, and also NGET's obligation under its transmission licence to maintain and develop its transmission system in an economic and efficient manner.

2.45. We propose to adopt NGET's proposal for a baseline allowance equivalent to the efficient costs of deploying undergrounding technologies for 10 per cent of the new transmission assets proposed for delivery in RIIO-T1. We recognise that this baseline amount could be too large or too little and is simply an assumption for setting the price control. Therefore, in light of this uncertainty we also propose to include a volume driver to adjust NGET's revenues for the level of mitigation technologies actually needed over the course of the price control to obtain development consent. We propose this adjustment would be calculated from the length of mitigation required for planning consent and the unit costs of the various technologies taken from the Institution of Engineering and Technology's report 'Electricity Transmission Costing Study'.[9] For more information on the operation of the planning requirements volume driver we refer the reader to the Costs assessment and uncertainty Supporting Document.

Our assessment

2.46. We consider NGET's proposal to include an allowance for mitigating the visual amenity impacts of new transmission assets is reasonable for business planning purposes. We also support NGET's proposal to set the baseline allowance on the efficient costs of undergrounding 10 per cent of new routes in its Best View alongside a volume driver to adjust revenues for the actual level of mitigation that turns out to be required. We believe this approach is consistent with our Strategy Document in which we said that addressing visual amenity issues is for the planning process rather than any fixed funding rule set through the price control. It also recognises that planning outcomes are a 'known-unknown' over RIIO-T1 and as such are likely to be more efficiently managed through an uncertainty mechanism triggered by case by case planning decisions than any pre-conceived assessment of the efficient level of mitigation.

2.47. We also note that our proposed approach is consistent with NGET's published policy on how it will, on a case by case basis, identify the location and technology for any new transmission route informed by stakeholder engagement. It is also in line

[9] A copy of the report can be found here: http://www.theiet.org/factfiles/transmission-report.cfm

with National Policy Statements on planning decisions which require proposers to show how they balance visual impacts against other factors, eg availability and cost of alternative sites, routes and technologies.

2.48. We did consider whether it would be appropriate to introduce alternative incentives on NGET around efficient decisions on undergrounding. However, we have rejected this on the basis that:

- It would be difficult to set a mechanism without taking a view on what constitutes an efficient level of undergrounding.
- NGET may be penalised or rewarded for decisions it cannot fully control.
- As a statutory consultee under the Planning Act 2008 we have the opportunity to seek further justification from NGET that its proposed mitigation measures represent good value for existing and future consumers.
- We can review NGET's performance in relation to meeting its relevant licence obligations.
- We will also monitor developments under this mechanism and we propose to retain the option to review the mechanism if it becomes clear to us it is not delivering efficient outcomes.

Our Initial Proposals – existing infrastructure in designated areas

2.49. In our Strategy Document we proposed to set an expenditure cap for TOs, on a use-it-or-lose it basis, to mitigate the impacts of existing transmission assets on the visual amenity of designated areas. We said the cap should be informed by willingness to pay (WTP) analysis. In our Final Proposals for SPTL and SHETL, we confirmed that the expenditure cap would be available for all electricity transmission owners.

2.50. The consumer WTP analysis NGET submitted in June 2012 provides evidence of positive and significant consumer WTP for visual amenity improvement in designated areas. In our assessment, NGET's analysis provides strong support for a consumer funded programme as part of RIIO-T1 to improve the visual amenity of designated areas. However, we do not consider NGET's analysis provides sufficient information at this time (due to limitations discussed below) to inform the level at which the expenditure cap should be set for the whole of the price control. We are mindful of our principal objective to protect the interests of existing and future consumers and are cautious about committing substantial consumer funds in the absence of sufficient information about consumer WTP. Instead we propose to set an initial expenditure cap of £100 million to allow TOs to work on delivering visual amenity improvements from the start of the price control while they complete further WTP analysis to inform the level of the enduring expenditure cap for the remainder of RIIO-T1.

2.51. In relation to the governance of the expenditure cap, we propose that the TOs would need to develop a policy for delivering visual amenity outputs in designated areas. We propose that this policy is approved by the Authority before TOs can access funding under the expenditure cap.[10] The Authority's assessment would consider the extent to which the TO's policy meets various principles, such as involving stakeholder engagement and input, delivering long term value for money for existing and future consumers and, overall, contributing to sustainable development. We also envisage that each TO will set out in its policy what constitutes a visual amenity output in a designated area and the relevant criteria the output would need to meet. To provide extra safeguards we also propose the policy includes the TOs proposed assessment process to verify that the output has delivered the defined impact on visual amenity.

Our assessment

2.52. At the start of June 2012 NGET submitted its consumer WTP analysis to Ofgem. Using data from a choice experiment[11] completed by 1,002 survey respondents across Great Britain, NGET modelled consumer WTP for 48 mitigation options. These options comprise combinations of four mitigation technologies in three different locations and of varying length. The modelled results give point estimates of average consumer WTP for each of the mitigation options. These range from 52p to £15 per year for eight years and are highest for respondents stated preferred mitigation technologies, areas of greatest landscape sensitivity and for mitigation options that covered longer distances. On the basis of its study conclusions, NGET propose an expenditure cap is set using the lowest average WTP estimate of consumer WTP for the preferred mitigation options. This is £6.40 per year for the eight years of RIIO-T1 giving a cap of £1.1 billion.[12]

2.53. We have reviewed NGET's WTP analysis and assessed this against the key features of best practice set out by London Economics (LE).[13] Drawing on academic literature and best practice guidance and recommendations published by other public bodies such as the Department for Environment, Food and Rural Affairs (DEFRA), the Competition Commission and HM Treasury, LE said that best practice for WTP studies is defined by:

- A clear statement of study objectives covering the non-market good being valued and the target population whose valuation is being estimated
- Justification for chosen study methodology to estimate WTP.
- Appropriate survey design to seek participants' valuation of non-market good including information about survey purpose, questions about participant's

[10] The TOs could develop this policy either before the start of RIIO-T1 or during RIIO-T1 but in order to have an approved allowance for a particular project under the expenditure cap the TOs would first need to have a policy approved by the Authority.
[11] A choice experiment is a particular approach for eliciting participants' valuation of the non-market good in which respondents are presented with a series of choices between alternative scenarios and they are asked to choose the scenario they prefer given the price and non-price attributes specified for each scenario.
[12] A £1.1 billion expenditure cap would underground around 45 miles of overhead line (OHL) (out of 243 miles of OHL currently in areas of outstanding natural beauty (AONB) and 119 miles of OHL in National Parks) if it cost £25m/mile on average.
[13] We commissioned London Economics to review NGET's July 2011 study of consumer attitudes to undergrounding. In this report they set out the key features of best practice for conducting WTP studies. A copy of London Economics report is available at:
http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/visualamenity.pdf

attitude to non-market good, valuation questions and follow up questions regarding participant's responses and socio-economic characteristics.
- Valuation questions with an appropriate description of the non-market good attributes, who would deliver the non-market good, who would pay, the method of payment, and how frequently payments would be required, as well as the inclusion of a no-choice option.

- Pre-testing of survey instrument with pilot group and focus groups to determine prior knowledge in target group about topic and appropriate level of attributes.
- Appropriate sampling techniques to get representative sample of target population.
- Appropriate analysis of survey data including frequency analysis, descriptive statistics, correlation analysis/cross tabulations, and regression analysis to explain determinants of different aspects of observed or stated choices.
- Assessment of potential bias in results and implementation of appropriate mitigation options, where necessary.
- Discussion of conclusions with respect to consumers' average, median or typical WTP for the non-market good in question taking into account any potential biases, any mitigating options that have been used and the validity of the results.

2.54. From our review, we consider that NGET has largely addressed the points above. However, in terms of the research conclusions NGET has only provided single point estimates of consumers' average WTP for visual amenity improvement in designated areas. In our view the omission of estimates of the median consumer WTP is a significant limitation of the analysis and overlooks a key recommendation in the LE report. LE specifically refers to deriving median estimates of WTP, alongside average estimates, as a key metric for informing the level of the expenditure cap as the median represents the level at which more than 50 per cent of consumers would be willing to pay.

2.55. We understand that a combination of the survey sample size and the number of parameters estimated from the choice experiment data meant that it was only possible to model the single point estimates of average WTP. Typically there is a trade off in this type of modelling work around the number of parameters that can be estimated from a given sample and we understand that NGET was keen that its analysis covered a range of mitigation options as this was a key limitation of its previous study. However, this has had implications for the information that could be derived about the WTP estimates and consequently NGET was not able to furnish estimates of the median consumer WTP.[14] In combination with the mean estimates, median estimates are important for understanding the variation of WTP across the sample and help inform better judgments about the appropriate level of the expenditure cap.

2.56. We believe that WTP could be very diverse across consumers and has a relatively skewed distribution.[15] If this is the case, the median estimate of WTP would

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[14] There were not enough degrees of freedom to estimate median WTP from the sample data. In statistics, degrees of freedom are the number of values in a study that are free to vary.
[15] Another limitation of the modelling approach is that it used an assumption that the estimated

be statistically significantly lower than the average WTP for visual amenity improvement in designated areas. Although not directly comparable, given differences in the specific research objective and the survey methodology and design employed, we note that NGET's July 2011 study found that median WTP was around half of the average WTP.

2.57. We also informed our proposal based on the other results of the survey. These showed that respondents' have very mixed attitudes regarding the affordability of such measures and whether these represent value for money at this time, as well as degree of priority and whether they should pay for such improvements.

2.58. In the absence of better information at this time, we are cautious about using the point estimates of the average WTP to set an overall expenditure cap for the duration of the price control. For these reasons and also having regard to our principal objective to protect existing and future consumers we are proposing to set an expenditure cap of £100 million for the start of the price control. The average WTP estimates show there is a positive and significant consumer WTP for visual amenity improvement in designated areas. The £100 million will allow the TOs to continue to work to deliver benefits for consumers from the start of the price control whilst NGET and/or the other TOs complete further WTP analysis to inform the level of the enduring expenditure cap for the remainder of RIIO-T1.

Broad Environmental Measure

Our Initial Proposals

2.59. We have published separately our decision to introduce an Environmental Discretionary Reward (EDR) as part of the price control to sharpen the environmental considerations of all the electricity TOs throughout the RIIO-T1 period.[16] The key aim of this incentive is to drive the TOs, including NGET, to adopt a proactive corporate and operational culture to facilitate the transition to a low carbon economy and improve environmental performance. We expect that the EDR will complement many of the RIIO-T1 outputs and encourage much more transparency from the TOs about how environmental considerations have been embedded in their strategy and operational practices.

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parameters have a normal bell-shaped distribution. This in effect would constrain any estimate of the median to not be significantly different from the mean value (in a statistical sense). This is unlikely to be a plausible result when inferring from the sample estimates about the true median and mean WTP in the population. We understand that assuming a normal distribution as a starting point for estimating sample parameters is standard practice. However, it would be desirable to revisit this assumption in future work to better approximate the true distribution and derive asymptotically consistent estimates of median WTP.

[16] Decision on the concept for the implementation of the Environmental Discretionary Reward for the electricity transmission owners and system operator http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=210&refer=Networks/Trans/PriceControls/RIIO-T1/ConRes

Our assessment

2.60. Relative to its July 2011 submission, NGET articulated a much more integrated approach in its March 2012 business plan to addressing its environmental impacts and sustainability in its business planning processes. We commend the initiatives NGET has put in place already to foster improvements in corporate and operational sustainability such as a climate change champion in different areas of the business, adopting a Whole Life Value policy, and piloting the reporting standard on scope 3 emissions. We encourage NGET to consider how it can demonstrate the impact of such initiatives as part of the assessment under the EDR and more importantly the extent to which such initiatives are embedded in the core business rather than an add on.

Wider system reinforcement works

Our Initial Proposals

2.61. To accommodate increases in generation flows and comply with the necessary security standards NGET has to develop and reinforce its transmission network. Under the RIIO output framework these reinforcement works on the main transmission network are Wider Works (WW) outputs.

2.62. Table 2.2 sets out the baseline WW outputs we propose NGET would deliver over the price control period. WW outputs are measured in terms of the transfer capacity across system boundaries. A system boundary splits the transmission network into two parts across which the capability to transfer electrical power can be assessed.[17]

2.63. Thermal, voltage and stability capabilities for each boundary are assessed in accordance with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS). NGET may phase work to increase either thermal, voltage, stability or a combination of these properties across system boundaries. In some cases investment to improve one element of boundary capability is not manifest in the transfer capability because another constraining capability exists temporarily (eg investment to improve thermal capability in the middle of the price control period will not show an increase in overall boundary transfer capability until a voltage constraint across the boundary is resolved by a later investment).

[17] For the avoidance of doubt, system boundaries are not network ownership boundaries and each licensee's network could contain multiple system boundaries.

Table 2.2: Baseline Wider Works outputs

MW	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
B6	3300	**4300[2]**	**6700[1]**	6700	6700	6700	6700	6700
B7	2000	**3400[2]**	**5800[1]**	5800	5800	5800	5800	5800
B7a	4900	5300	**7700[1]**	7700	7600	7600	7600	7600
B8	11300	11300	11300	11500	11500	10600	10600	10600
B9	12600	12600	12600	11500	11500	11500	11500	11500
B10	5800	5800	5700	5700	5700	5700	5700	5700
B11	9900	9900	10000	10000	10000	10000	10000	10500
B12	5800	5800	5100	5100	5100	5100	5100	5200
B13	1800	1800	1800	1800	1800	1800	1800	1800
B14	9600	9600	9600	9600	9600	9600	9600	9600
B14e	8700	8700	9400	10150	10150	10150	9950	9950
B15	6400	6400	6400	6400	6400	6400	6400	6500
B16	15200	15500	15500	15500	15500	15500	15500	15500
B17	5200	5200	5200	5200	5200	5200	5200	5200
NW1	1800	1800	1800	1800	4400	4400	4400	4400
NW2	1500	1500	1500	4600	4600	4600	4600	4600
NW3	2900	2900	2900	2900	**4400[2]**	4400	4400	4400
NW4	6000	6000	6000	6000	6000	6000	6500	6500
EC1	4100	4100	4100	4100	4100	7000	7000	7000
EC3	3200	3200	**4300[2]**	4300	4300	4300	4300	4300
EC5	2600	2600	**3600[3]**	3600	6800	6800	6800	6800
SC1	5600	5600	5600	5600	6100	6100	6600	6600

Notes:
1 Capacity increase of 2,400MW delivered by Western High Voltage Direct Current link between Scotland and Wales will affect boundaries B6, B7 and B7a.
2. Capacity increases from delivery of scheduled baseline WW outputs in Table 2.3.
3. Scheduled baseline output delivers 1,700MW but voltage constraint limits increase to only 1,000MW increase in boundary transfer capability.

2.64. In total, the baseline WW outputs in Table 2.2 would give a gross increase in transfer capability of 28,600MW across system boundaries in NGET's transmission area. Together with the prospective Strategic Wider Works (SWW) outputs (potentially a further 22,000MW) set out in the Cost assessment and uncertainty Supporting Document the proposed increase in transfer capability over RIIO-T1 is broadly consistent with the level of reinforcement needed to accommodate the UK's renewable energy targets.

2.65. The Baseline outputs in the above table include the Western High Voltage Direct Current (WHVDC) link. The WHVDC link is being jointly delivered by NGET and SPTL, and forms part of their respective baselines under RIIO-T1. In May 2012 we consulted on the details of our proposed funding arrangements for the WHVDC link for under Transmission Infrastructure Incentives (TII) and RIIO-T1, for both NGET and SPTL.[18] Alongside this document we are publishing our final decision on the ex ante allowances and risk sharing arrangements between the transmission companies and consumers for this project under TII (to end 2012-13) and RIIO-T1 (from 2013-

[18] See TII webpage, where all documents related to TII that are referred to in this letter can be found: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Pages/InvestmentIncentives.aspx

14 onwards). As such, these matters are out of scope of this consultation on our Initial Proposals for NGET. We will insert details of the licence changes for both NGET and SPTL in line with this decision, with baseline WW outputs based on delivery of additional transfer capability between Scotland and Wales (affecting Boundaries B6, B7, B7a) consistent with a continuous rating of 2.25GW and a short-term (6 hour) rating of 2.4GW.

2.66. Several of the proposed baseline WW outputs in Table 2.2 have a strong needs case for delivery in the first half of the price control (the bolded figures in table 2.2). NGET has previously received part funding for some baseline WW outputs through the TII and several of these WW outputs are already in construction, or shortly due to start, including also the WHVDC. Therefore we propose to set a scheduled date by which NGET will have to deliver these by. The project specific WW outputs and scheduled delivery dates, other than those for the WHVDC link, are set out in Table 2.3.

Table 2.3 Scheduled Baseline Wider Works Outputs

Project	**Wider Works Output (additional boundary capability)**	**Scheduled for delivery in Regulatory Year**
Harker Hutton Re-conductoring	Boundary 7: 1400MW increase	2013/14*
Series and Shunt Compensation (Anglo-Scottish Incremental schemes)	Boundary 6: 1000MW increase	2014/15
Re-conductoring Norwich-Walpole; turning-in Norwich-Sizewell circuit at Bramford; and extending Bramford substation	Boundary EC3: 1100MW increase Boundary EC5: 1700MW increase	2014/15**
Re-conductoring of Trawsfynyyd-Treuden Tee	Boundary NW3: 1500MW increase	2015/16***

Notes:
* This project is scheduled to complete in 2013/14 but the benefits of this scheme on the boundary transfer capability will not be fully realised until the Anglo-Scottish incremental schemes are completed in 2014/15.
**This project is scheduled to complete in 2014/15 to take advantage of delivery synergies with non load related work. However, the benefits of this scheme on the boundary transfer capability will not be realised until Deeside-Trawsfyndd sometime around 2017/18.
*** The additional transfer capability across EC5 boundary will not be realised until the Bramford-Twinstead OHL and the installation of a Mechanically Switched Capacitor at Barking is completed sometime around 2017/18.

2.67. We propose that NGET will need to confirm delivery when it has commissioned a scheduled WW output, and provide relevant supporting evidence. We propose to review NGET's performance in delivery of the outputs, including any deviations from agreed completion timescales to determine whether these constitute a contravention of NGET's licence conditions. In such circumstances, we propose to determine whether NGET has been complied with the timely delivery requirements specified in the licence. In considering whether there has been a potential breach of the licence, we would look at the relevant factors leading to the late delivery, the amount of consumer detriment caused and the extent to which NGET could be held responsible for events as well as whether or not they took reasonable steps to mitigate the impact of such events where they could do so efficiently.

2.68. If we are satisfied that the late delivery constitutes a breach, NGET could be subject to a financial penalty which would be determined under the Authority's Statement of Policy with respect to Financial Penalties. [19]

2.69. In the event that NGET under or over delivers in relation to the specific WW outputs in table 2.3 we propose to adjust allowed revenue to match the delivered output using a WW volume driver.

2.70. For the remainder of baseline WW outputs in table 2.2 (excluding the WHVDC) there is some uncertainty around the exact timing of when these will be needed. We note that the timing and magnitude of these WW outputs are based on the Gone Green scenario of the generation and demand background and therefore these could change if the actual background is different to the Gone Green scenario.

2.71. Given this uncertainty, we do not propose to specify a scheduled delivery date for these outputs. Instead we propose, consistent with NGET's business plan, that NGET develops a Network Development Policy (NDP) setting out how it will assess whether or not WW outputs are needed and the process it will use to update its investment programme.

2.72. Subject to the Authority's approval of NGET's NDP, NGET would have discretion to advance these works when the WW outputs meet the criteria set out in its NDP. Under this arrangement, WW outputs that met the NDP criteria, excluding those in Table 2.3, would be subject to further assessment and confirmation under NGET's annual NDP and stakeholder engagement process. For the avoidance of doubt, we propose that this would include WW outputs that are additional to the baseline.

2.73. For outputs delivered in accordance with its NDP we propose to adjust NGET's baseline revenue to match the efficient costs of the delivered WW outputs through a WW volume driver and boundary specific unit cost allowances for additional transfer

[19] Ofgem Utilities Act Statement of policy with respect to financial penalties, October 2003. This is available on our website at http://www.ofgem.gov.uk/About%20us/Documents1/Utilities%20Act%20-%20Statement%20of%20policy%20with%20respect%20to%20financial%20penalties.pdf.

capacity (for more information on the volume driver and unit costs please see the Cost assessment and uncertainty Supporting Document).

2.74. The advantage of this proposal is that it provides efficient arrangements for NGET to progress relatively small to medium sized wider works with minimum regulatory input. It also makes NGET's network investment appraisal process more transparent and provides an opportunity for stakeholders to have input to this process.

2.75. In our view NGET should set out in its NDP how it will assess both the need and optimal timing of delivering WW outputs that ensure long term good value for consumers. To provide safeguards that consumers only pay for new infrastructure that is needed (ie to avoid stranded assets) we believe NGET's NDP should only apply when the proposed WW outputs have:

- a needs case with diverse potential users
- a high degree of user commitment, ie 70 per cent or more
- a relatively short lead time ie up to three years
- a positive needs case under a range of generation and demand scenarios.

2.76. We have reviewed the initial draft NDP included in NGET's March business plan. In our view NGET's draft NDP could be improved with the following additions and amendments:

- Explanation of internal processes, tools and methodology for modelling costs and benefits of network reinforcement and an assessment of modelling performance to date
- Application of judgement or probabilistic weighting to the generation/demand scenarios
- Explanation of NGET decision rules for advancing WW outputs into the investment plan and how these ensure long term good value for consumers
- Further explanation about how NGET would revise its investment programme if an annual review of investment plans suggested that the case for a WW output in construction had weakened
- Inclusion of a general review of outcomes under the NDP in the latter half of the price control
- Further consideration of the opportunities for stakeholder consultation and input.

2.77. We note that NGET will need to do further work on the NDP over the coming months in order to provide an updated draft NDP before the end of the year for the Authority's consideration.

2.78. Consistent with our Strategy Document, NGET proposed in its business plan that all large reinforcements above £500 million in its Best View, known as SWW, and WW outputs not meeting its NDP criteria, would be subject to a within period determination by Ofgem on the needs case and efficient costs of the specific project and output delivery. More information on the proposed arrangements for taking forward these outputs is set out in the Cost assessment and uncertainty Supporting Document.

2.79. We also propose NGET would deliver pre-construction engineering works for the SWW and WW outputs. These pre-construction deliverables are: routing, siting and optioneering studies, project design, environmental assessments, technical specifications for cost tender, and planning consents. For more information on our Initial Proposals for baseline funding for pre-construction engineering works see the Cost assessment and uncertainty Supporting Document.

Our assessment

2.80. NGET developed its Best View of the WW outputs that might be required during RIIO-T1 to meet the industry derived Gone Green scenario. Under this scenario NGET would have to reinforce its network to accommodate the additional flows from more than 30 gigawatts of new generator connections and comply with the relevant security standards.

2.81. In our Strategy Document we said that each TO should develop its business plan on its 'Best View', or best estimate of the outputs it could be required to deliver to the end of RIIO-T1. This is important for business planning as it ensures the TO fully considers the deliverability and financeability of its plan, implications of the level of delivery for resourcing and organising the business, as well as the phasing of delivery, particularly where there might be synergies or conflicts in output delivery.

2.82. Whether the amount of WW outputs NGET actually delivers over RIIO-T1 is the same as its Best View is dependent upon the quantity and location of new customers, particularly new generation customers and changes in demand for existing customers. As a result there is considerable uncertainty around the amount and timing of WW outputs NGET will actually deliver over the price control period.

2.83. For these reasons, our assessment of NGET's business plan for WW outputs has focused more on NGET's proposals for managing the uncertainty around the volume of outputs rather than the particular volume of outputs NGET proposed to deliver. This also has important implications for the level of risk sharing with consumers.

2.84. For the most part, our Initial Proposals for NGET's WW outputs and uncertainty mechanisms reflect the proposals outlined in NGET's March business plan, which in turn largely reflect our Strategy Document. We have proposed some changes relative to NGET's March Business Plan in our Initial Proposals in relation to the balance of funding NGET would receive through the baseline and through the various uncertainty mechanisms such as the WW volume driver and the SWW within period determination. This would mean that a larger proportion of NGET's funding for the Best View of WW outputs required during RIIO-T1 would come through uncertainty mechanisms than NGET had proposed.

2.85. Overall we believe our Initial Proposals for WW outputs represent a better balance of risk sharing between NGET and consumers than NGET proposed. Our proposals would ensure there is enough flexibility and certainty in the price control settlement to allow NGET to meet any changes in the generation and demand background. Our proposals will also protect consumers by ensuring they only pay for new infrastructure that is needed (ie reduced risk of stranded assets) and that NGET faces strong incentives to deliver WW outputs efficiently and innovatively.

Other outputs

System Operator and European activities

2.86. In our assessment of the efficient amount of revenue that NGET needs for 2013-2021 we considered its ability to provide SO activities (SO internal costs). We also considered funding within the company's operating expenditure in relation to meeting its ongoing commitments driven by developments in European policy and legal framework, particularly the Network Code developments.

2.87. The details of the cost assessment in these areas are set out in the Cost assessment and uncertainty Supporting Document.

2.88. The outputs driven by the SO internal costs are the long-term delivery of the SO function and this will be reflected in the SO outputs and incentives described in our SO incentives from 2013 document also being published today.

2.89. As part of the annual monitoring of NGET's performance against its other outputs we will want to understand that it has contributed to the ongoing European regulatory developments and played its full part in this area.

3. NGGT: Outputs and incentives

Chapter Summary

This chapter sets out the outputs that we propose NGGT should deliver and the associated incentives around delivery over the RIIO-T1 period. We set out Initial Proposals, and then describe our assessment of the proposed outputs in NGGT's business plans. We highlight where our Initial Proposals directly reflect the proposals in NGGT's business plan and where they differ.

Question 3: Do you have any comments on our Initial Proposals on NGGT's output and incentives?

Question 4: We welcome your views on the appropriate permits arrangements from 1 April 2014 if no other changes to the incremental capacity arrangements have been made?

Question 5: We welcome your views on the two options on constraint management tools retained in our Initial Proposals. Are you aware of any evidence that might help us in judging between these two options?

Introduction

3.1. This chapter sets out our Initial Proposals for the outputs we expect NGGT to deliver during the RIIO-T1 period. It also presents our Initial Proposals on the associated incentives that will apply around delivery.

3.2. The gas industry has well developed industry governance arrangements, which allow industry stakeholders to discuss and design code changes reflecting changes to the industry commercial arrangements. These stakeholders have played a major part in the RIIO-T1 price control through representation in our stakeholder engagement and in NGGT's engagement including its 'talking networks' workshop series. In some areas, RIIO-T1 reflects outputs that the industry has previously established. In other areas, it includes outputs reflecting issues and changes considered by the industry in parallel to the RIIO-T1 work. An example of the latter is the connections output where the industry work in this area is reflected in our Initial Proposals on what NGGT is required to deliver.

3.3. In most areas, these Initial Proposals set out a fully developed package of outputs and incentives to cover the full RIIO-T1 period. However, in relation to two areas we are not able to set out fully developed proposals. These are as follows:

- NGGT's incremental capacity proposals - we recognise that the arrangements we are setting out may need to change during RIIO-T1 to reflect further work that NGGT is currently taking forward with the industry to develop long term arrangements. We expect NGGT to facilitate the industry processes needed to determine these long term arrangements and to target facilitating any changes, if appropriate, for 1 April 2014.

- Constraint management - NGGT only provided relevant details of its proposed output and incentive arrangements in its 31 May 2012 submission with its SO incentives plan. We are consulting on two potential options. These are set out in the relevant section below.

Outputs we are requiring NGGT to deliver over RIIO-T1

Safety

Our initial proposal

3.4. We propose that NGGT's primary output in this area should be compliance with its legal safety requirements. These requirements are monitored by the Health and Safety Executive (HSE) as the safety regulator.

3.5. In addition, we propose a suite of secondary measures that inform both the safety and reliability of its network relating to asset health, condition and criticality.

Our assessment

3.6. Our Initial Proposals are consistent with NGGT's business plan, which in turn was consistent with our Strategy Document. Our strategy decision outlined an output that reflects a continuing high level of safety and is subject to HSE scrutiny.

3.7. The asset health, condition and criticality measures that NGGT will need to provide and maintain are relevant to provision of both a safe and reliable gas network. These measures will assist in informing us about the state of the network now and will bring transparency on its future health and condition into the next price control period.

Reliability and availability

Our Initial Proposal

3.8. We propose that NGGT should be required to provide a level of network capacity sufficient to convey gas volumes at system entry and exit points in line with existing requirements under the Uniform Network Code (UNC), its Gas Transporter (GT) Licence and ultimately, the Gas Act.

3.9. This output would require NGGT to deliver, subject to Section 9 of the Gas Act, on its Standard Special Condition A9 obligation to plan and develop its pipeline system capable of meeting 1 in 20 peak aggregate daily demand. It would also require NGGT, subject to the provision of other conditions within the licence, to meet its baseline entry and exit capacity obligations.

3.10. This output would also require delivery of existing lead times included in NGGT's licence relating to how NGGT responds to signals for incremental entry and exit capacity (42 and 38 months respectively). We propose for this part of the output to be accompanied by a permits[20] allowance for the first year of RIIO-T1 (from 1 April 2013 – 31 March 2014). Permits provide a means by which NGGT can move the obligate lead times for the release of incremental capacity. Their use enables NGGT to trade off the risk of more difficult projects with those of other projects.[21]

3.11. We propose that this 'first year' permits allowance value would be £19 million. For other years of RIIO-T1 ie from 1 April 2014 we seek consultees' views on the permits arrangements[22] that should apply if no changes have yet been made to the incremental capacity arrangements. Should they for instance return to a level equivalent to those set out in the TPCR4 rollover period? Any change to the incremental capacity arrangements then implemented would need to consider the appropriate way to incentivise NGGT in this regard from that point onwards. As set out in the finance Supporting Document the approach used for revenue recovery is changing to a total expenditure (totex) approach[23]. This has implications for the funding of incremental gas transmission capacity, particularly the timing of revenue release. From a practical perspective, this means that where revenue drivers are needed these will need to be calculated up front by NGGT. In doing so it will need to use up to date unit cost information.

3.12. We are aware of ongoing industry discussions around NGGT's proposals for changes to the incremental capacity arrangements. Our Initial Proposals are that if further changes to the incremental capacity arrangements become needed during the control period then we will consider these.

3.13. Finally, in relation to constraint management, given the timing of NGGT's proposals being submitted, we are consulting on two alternative options:

- A variant of NGGT's proposed single unified incentive covering entry/exit and operational/incremental actions but with no caps and collars on the incentive.

- The retention of the existing separate incentive schemes. This is an alternative, particularly if further analysis and discussion with stakeholders identifies major weaknesses in NGGT's proposal.

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[21] Permits have no value until the end of the period – NGG gets to keep the cash value of any unused permits from its allocation for the period, plus any additional permits it has earned during the period for early delivery (up to the cap).
[22] Historically, revenues from permits have been treated as SO in NGGT's licence. We propose that the 'first year' permits allowance (and any other permits allowance going forward) would relate to the TO activities in the licence. This reflects the role that is the most relevant to the use of permits.
[23] See the Finance Supporting Document.

Our assessment

Existing obligations for baseline capacity

3.14. Our Initial Proposals are consistent with our strategy decision. They are largely consistent with much of NGGT's business plan although there are differences. Our reasons for these differences are set out below.

3.15. NGGT's business plan was consistent with delivering existing obligations. A significant proportion of its stakeholder engagement focused on whether in the light of changes to the wider gas system (particularly sources of supply and demand and certainty around short term gas flow changes) it needed a new output measure that it labelled 'network flexibility'. It considered, in response to the challenge by us and other stakeholders, whether there was a way of identifying clear output metrics that would measure what additional 'network flexibility' expenditure would provide to users of the network and consumers. To date NGGT has not identified any additional output measure over the existing obligations identified as part of the suite of outputs and incentives set out in this document. The Cost assessment and uncertainty Supporting Document considers this issue in more detail including possible changes during the RIIO-T1 period.

3.16. NGGT did not propose a review of baseline capacity at the entry and exit points. We propose to retain the existing baselines.

3.17. NGGT refers to the situation at Fleetwood. This is a location where a shipper requested a new entry point to be created. Capacity at this entry point was booked from October 2010. Early capacity holdings have lapsed and at the present time it is unclear whether the future capacity as signalled by this shipper will be needed. We will continue to monitor the situation and should circumstances arise which require Ofgem to take action to protect the interests of consumers, we will take the appropriate steps to ensure an economic and efficient outcome is achieved (which might affect the treatment of capacity at Fleetwood). This represents how we would expect to act in any similar situation, as we will generally consider taking steps in accordance with our principal objective to protect the interests of consumers.

Incremental capacity

3.18. In March 2012, NGGT proposed significant changes to what it is required to do in response to signals for extra capacity at either entry or exit points.

3.19. For the first time, in its March 2012 business plan NGGT set out a complete proposal for adapting current incremental capacity arrangements to deal with the impact of the new planning arrangements in England and Wales under the Planning Act 2008. This included:

- removal of the existing lead times which cover both planning and construction risk implying a significantly longer overall lead time (but with a commitment to a shorter phase of 24 months for the construction period)
- provision for a bilateral agreement (including details on the delivery process) with the user who signals the need for extra capacity
- changes to the auction process
- a two stage revenue driver calculated as a project progresses
- changes to its revenue profile and capitalisation rate.

3.20. NGGT is right to consider the impact of the Planning Act 2008. To date there have been no infrastructure related cases which have proceeded completely through the Planning Act 2008 process with either the Infrastructure Planning Commission (IPC) or now through the Planning Inspectorate (PI). Consequently, we recognise that there is uncertainty about its full implications.

3.21. NGGT's proposal contained many elements with potentially significant benefits both in terms of providing certainty in the final delivery phase and around the degree of user commitment needed to commence significant network reinforcement works.

3.22. However, the proposals also imply significant changes not just to NGGT's licence but to its Code arrangements including aspects whose change is likely to need significant Code changes. Such changes should be discussed with industry, and will require industry development through the normal code modification processes. It is clear that there is no likelihood of these industry discussions being finalised or the necessary code modification processes having run their course in time for implementation from 1 April 2013.

3.23. This drives our initial view that we are not in a position to include NGGT's proposals in full in this area. Instead our Initial Proposals retain the lead times currently in NGGT's licence.

3.24. We worked with NGGT to understand the options available, in light of the likely absence of industry developed changes in time for 1 April 2013. A number of options were considered but essentially we faced a choice between retaining the existing lead times, or moving to something approximating the new arrangements in provisional form eg through changes to methodology statements such as the incremental capacity methodology statements.

3.25. We think it is important that we do not prejudge the industry process on the proposals. Therefore we propose to retain the existing lead times until any further changes are developed. We recognise that if NGGT's judgement of the timings and process associated with the new planning arrangements is correct (dependent on the signals for new capacity faced), NGGT could face challenges in meeting these obligations. Therefore we agree with NGGT's proposal that the permits allowance be used in tandem with the current lead times to help NGGT manage the impact of the new planning arrangements, and avoid the requirement for an excessive call on constraint management to cover the period between the obligated lead times and the actual delivery of capacity. NGGT proposed a permits allowance to the value of £39 million[24] to be applied across both the year 1 April 2013 – 31 March 2014 and the preceding year 1 April 2012 – 31 March 2013 (in recognition of possible signals at the March 2013 auction).

3.26. To manage additional risk driven by the planning process we propose to include a permits allowance for the year 1 April 2013 – 31 March 2014, to the value of £19 million. This proposed allowance has been informed by NGGT's analysis, However, we have not included the requested allowance for the roll-over year on the grounds that NGGT accepted the TPCR4 roll-over decision, having failed to demonstrate the need for an increased level of permits.

3.27. NGGT also proposed having the ability to 'overdraw' its permits by 50 per cent in volume terms. Its reward/penalty related to this would be limited to £30 million upside and £10 million downside for NGGT. Our Initial Proposals do not include this change to the existing arrangements. We think that retaining the existing principles is consistent with this short term arrangement being effectively a retention of current arrangements.

3.28. Going forward we will play a full role with other stakeholders and NGGT in relation to the development of long-term arrangements. We consider it is important that the enduring arrangements share risk fairly between the parties.

Constraint management

3.29. NGGT has tools available to manage network capacity. These tools offer a means of dealing with situations where NGGT cannot deliver capacity that has been commercially committed to a shipper/supplier. Constraints on the network drive such situations. These constraints can be caused by a number of factors, some partially within, others wholly outside NGGT's control. For instance, they can result from situations where the physical use of the network by a particular shipper exceeds the commercially committed capacity, known as overruns. Constraints can also be the result of a localised imbalance between demand and supply or result from actions being taken on the network eg planned compressor outages by NGGT.

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[24] This value is derived applying the rate of £5,000 per permit. This is the value given in relation to entry in the TPCR4 rollover.

3.30. At present, NGGT is subject to a range of incentive schemes set out in Table 3.1. The operation of these schemes is dependent on whether the constraint management action taken is related to or unrelated to signals for new capacity, and on whether it relates to entry or exit points from the National Transmission System (NTS). Each of these tools has a target and some of them also include a limit on the upside and downside financial impact on NGGT (caps and collars). There is also an overall cap on NGGT liability across the different schemes currently set at around £55 million.

Table 3.1 Existing buyback schemes

Buyback Incentive	Target (£m)	Sharing Factor	Cap (£m)		Collar (£m)	
			month	year	month	year
Entry Capacity Operational Buyback	15.48	50 per cent	N/A	15.48	N/A	11.47
Entry Capacity Incremental Buyback	0	100 per cent	4.59	41.28	N/A	0
Exit Incremental Investment Buyback	0	100 per cent	4.59	41.28	N/A	0

An overarching cap across the schemes of £55.05 million.

3.31. NGGT propose to replace the existing schemes with a single unified incentive. This would span entry and exit and also relate to both operational buyback of capacity (unrelated to changes in the level of capacity provided) along with incremental buyback (directly related to the provision of extra capacity following signals at entry or exit points).

3.32. The full detail of this proposal was submitted with NGGT's SO business plan on 31 May 2012. As a result, we have only had limited time to evaluate fully the proposal which is a matter for RIIO-T1 rather than the SO incentives. Based on the evidence from NGGT there appear to be some positive arguments for introducing the simple unified incentive. These fall into two main categories:

- it would encourage better decision making (removing any distortions created by the individual schemes and allowing NGGT to make the most efficient decision across the full range of possible constraint management actions)
- it would generate resource savings (removing the need for categorising across the different schemes for the sole purpose of facilitating the incentive calculation.

3.33. We understand that stakeholders as yet appear to be unconvinced by the proposals and want to understand more about the reasons for change. We are aware, for instance, of the need to examine whether unifying these incentives would have a detrimental impact on particular categories of network users eg at entry. There are also potential costs to be considered. Removal of individual incentives might result in the loss of valuable information as to the causes of constraint, and how these might better be managed going forward.

3.34. Therefore we are also consulting, as an alternative, on retention of the current incentive schemes, although we are keen to understand views on NGGT's unified proposal.

3.35. NGGT's proposal is that the unified incentive scheme has a cap and collar set at £20m each year. We have informed our wider assessment of the risk associated with NGGT's package as a whole (see the Finance Supporting Document) with NGGT's own analysis. We recognise the need to balance the risk facing NGGT with the risk passed on to users once the limitation on the downside incentive is reached. While the costs and revenues related to constraint management actions are variable and in some areas past data is either scarce or not good for predicting future levels, we consider the risk of removing caps and collars based on NGGT's analysis to be reasonable. We have factored this in to our general risk analysis of the overall package.

3.36. We understand when using NGGT's analysis that it carried out detailed modelling to forecast the volume of constraints, and associated revenues. It also included assumptions about costs incurred. It calculated the maximum upside and downside for each year of the RIIO-T1 period, but also assessed a RIIO-T1 period estimate based on modelling which took account of the mix of good and bad years likely (rather than one based exclusively on bad years). From this analysis we are comfortable that NGGT's exposure is broadly equivalent to its preferred approach of caps and collars of £20 million. Using the RIIO-T1 period totals with no caps and collars provides a likely maximum downside of £23 million (though with a reduced maximum upside of £11 million). We recognise that to get the expected value of £0 within such an incentive the target levels would need to be set consistent with NGGT's proposals. At this stage we assume this to be the case but reserve the right to carry out further work to challenge each of these underlying assumptions.

3.37. NGGT has also proposed to merge the two Transmission Support Services (TSS) incentive schemes, the Constrained LNG (CLNG) and the Long Run Contracting Incentive, in to a single scheme. We propose to bring these incentives together, consistent with NGGT's proposal but we reserve the right to consider changes to the targets. We recognise that we will need to review the incentive as a result of any pipeline solutions being delivered to replace NGGT's reliance on the services provided by the Avonmouth LNG storage facility owned and operated by NG LNG.

Customer Satisfaction

Our Initial Proposals

3.38. We propose that NGGT should include a gas transmission specific element to its wider survey of customers and stakeholders. Its gas transmission and related system operator stakeholder engagement will also be eligible for consideration for reward through the discretionary reward in this area.

3.39. There is ongoing work to design the survey and to link this to a financial incentive. We are also working developing guidance for the application of a discretionary reward for exceptional outcomes from stakeholder engagement.[25]

3.40. Appendix 1 of this document provides a progress update on the ongoing work by all the TOs including NGGT on survey development and incentive design.

Our assessment

3.41. NGGT proposes to apply a financial incentive which, when fully implemented, would range from a penalty of 1 per cent of annual allowed revenue to a reward of 1 per cent of annual allowed revenue.

3.42. In addition, NGGT proposes to include a discretionary reward for delivering exceptional results through effective stakeholder engagement. It proposes this could be as much as 0.5 per cent of annual allowed revenue.

3.43. NGGT's proposals in this area are consistent with our Strategy Document.

3.44. For NGGT, we expect the survey and related information to identify clearly the company's role and focus on its activities. It will need to be informed by its gas customers and stakeholders.

Connections

Our Initial Proposal

3.45. We propose that NGGT should have a primary output to meet the new obligations set out in UNC modification 373 (UNC 373). A brief description of UNC 373 is included in our assessment below. Further detail is available from our decision letter in relation to that modification.[26] There is no financial incentive related to this but a clear reputational incentive is provided by the new process. We will also consider whether UNC 373 needs to be complemented by licence obligations on NGG in relation to connections.

3.46. We also propose to consider further refinement to the connections output in line with any enduring changes to the capacity arrangements.

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[25] (see RIIO-T1/GD1: Draft licence conditions – First informal licence drafting consultation being published alongside this consultation)

[26] Ofgem: Modification proposal: Uniform Network Code (UNC) 0373: Governance of NTS connection processes. (http://www.ofgem.gov.uk/Licensing/GasCodes/UNC/Mods/Documents1/UNC373D.pdf)

Our assessment

3.47. Our Strategy Document noted the absence of a detailed process for the provision by NGGT of connections to the gas transmission network. We recognised that industry discussions were already underway to establish a process and indicated that we expected NGGT's business plan to consider these evolving arrangements as a likely basis for the RIIO-T1 output in this area.

3.48. On 4 July 2012 the Authority directed the approval of UNC 373. For the first time in gas transmission this established a formal process for connecting to the NTS. We propose that NGGT's RIIO-T1 output in this area should be to meet the obligations provided for under this modification. This modification is now being implemented by the industry.

3.49. During the industry process leading to UNC 373 being approved, National Grid's customers did not favour financial incentives being applied.

3.50. NGGT is now proposing to link up its work on connections with its work on incremental capacity. This has potential advantages but we are concerned that it should not reduce NGGT's obligations as established under UNC 373. Both our strategy decision in this area and NGGT's initial business plan in July 2011 recognised that UNC 373 might not cover all the requirements of a connections output for the whole RIIO-T1 period.

Environmental outputs

<u>Business Carbon Footprint</u>

Our Initial Proposals

3.51. In line with our strategy decision we propose that NGGT reports annually to stakeholders on its scope 1 and scope 2 greenhouse gas (GHG) or carbon dioxide equivalent emissions at business level throughout the RIIO-T1 period. We note that NGGT set out similar commitments in its March business plan.

3.52. NGGT will face reputational incentives only on its BCF reporting.

Our assessment

3.53. NGGT provided better information in its March 2012 business plan about its BCF compared to its July 2011 plan. In particular, NGGT provided more context on the issues it faces around operating compressors on its network, the key sources of emissions at the business level, and how its proposals sit in relation to relevant legislative requirements.

3.54. NGGT forecast its scope 1 and scope 2 emissions (as TO and SO) will fall from nearly 700,000 tonnes in 2013 to around 385,000 tonnes at the end of the price control. This will depend on the number of compressors it needs to replace at sites that are emitting high levels of NOx emissions (to comply with legislative requirements) with more efficient technologies and electric powered compressors.[27] We note that the reduction in NGGT's BCF would also depend to a large extent on the rate at which the UK's electricity generation mix decarbonises as the electricity used to power the new compressors will create indirect (scope 2) carbon dioxide emissions at source. NGGT also will achieve some emission reductions through improved energy use in buildings.

3.55. We note that NGGT proposals are consistent with stakeholder feedback that it should invest in the minimum to ensure legislative compliance.

3.56. We reiterate our position that NGGT is required to report on its BCF at the business level to enable accurate reporting and monitoring on its BCF from the transmission business.

Other outputs

System Operator and European activities

3.57. In our assessment of the efficient amount of revenue that NGGT needs for 2013-2021 we considered the revenue NGGT required for its provision of SO activities (SO internal costs). We also considered funding within the company's operating expenditure for meeting its ongoing commitments arising from European regulatory changes, particularly helping to develop European Network Codes.

3.58. The details of the cost assessment in these areas are set out in the Cost assessment and uncertainty Supporting Document.

3.59. The outputs driven by the SO internal costs relate to the long-term delivery of the SO function and this will be reflected in the SO outputs and incentives described in our SO incentives from 2013 document also being published today.

3.60. We consider the funding package should allow for significant improvements in the way the SO function operates because of the significant SO internal revenue being allowed. We will monitor progress against the deliverables set out in the business plan.

3.61. As part of the annual monitoring of NGET's performance against its other outputs we will want to understand that it has contributed to the ongoing European regulatory developments and played its full part in this area.

[27] NOx is a generic term for mono-nitrogen oxides NO and NO2 (nitric oxide and nitrogen dioxide). They are produced from the reaction of nitrogen and oxygen gases in the air during combustion, especially at high temperatures. NOx react to form smog and acid rain. NOx are not a greenhouse gas.

RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas

4. Encouraging innovation

Chapter Summary

This chapter sets out the arrangements that we are proposing to apply to encourage NGET and NGGT to innovate to drive improved outcomes for consumers in RIIO-T1 and beyond.

Question 6: We welcome your views on the proposed level of funding for the licensees' Network Innovation Allowance (NIA), based on the quality and content of their innovation strategies.

Question 7: In relation to funding the Gas Network Innovation Competition (NIC) for 2013/14, do you support either option 1 (run the NIC and raise the required funds from the winning licensee's customers) or option 2 (no Gas NIC, but roll-over funds to 2014/15). If the NIC is delayed beyond 2014/15, what option would you support?

Introduction

4.1. The RIIO framework recognises the significant challenges faced by Britain's gas and electricity industries. Network companies need to facilitate the move to a low carbon economy while maintain safe, secure and reliable networks at least cost. In order to achieve these objectives, the companies will need to adopt new technologies and innovate to a greater extent.

4.2. Incentives for innovation are embedded in the RIIO model. Companies are incentivised to innovate to meet outputs in the most efficient way and the longer price control strengthens these incentives. In addition, we set out the three elements of an innovation stimulus package in our March 2011 strategy document:

- **Network Innovation Allowance (NIA)** - The NIA is a set allowance that each of the RIIO network licensees will receive to fund small-scale innovative projects as part of their price control settlement.
- **Network Innovation Competition (NIC)** - The NIC is an annual competition for funding larger more complex projects. The NIC will comprise of two competitions - one for gas and one for electricity.
- **Innovation Roll-out Mechanism (IRM)** - A Revenue Adjustment Mechanism that enables companies to apply for additional funding within the price control period for the rollout of new, proven solutions with demonstrable and cost effective low-carbon or environmental benefits. The mechanism will apply to projects which would not otherwise be commercially viable within the RIIO-T1 price control period.

4.3. In addition to describing the overall innovation stimulus framework, we also set out a requirement for companies to detail how they had considered the use of innovative approaches in their business plans.

4.4. The Strategy Document required each network operator to include an innovation strategy as part of its business plan, explaining the company's approach to innovation, its motivation and objectives.[28] We set out that the level of funding available through the NIA would be linked to the innovation strategy. We set out in the Strategy Document that the NIA would be capped at 0.5-1 per cent of allowed revenue. We set out that companies wishing to spend more than 0.5 per cent of allowed revenue should request that higher amount in their innovation strategy (up to a maximum of 1 per cent of allowed revenue). In making such a request the companies were required to provide justification for the additional funds. We set out that such requests would be judged by the quality and content of the innovation strategy as well as the company's justification.

4.5. In general, the innovation stimulus will be introduced as part of the RIIO-T1 and GD1 price controls on 1 April 2013. The exception may be the Gas NIC. In March 2012 we announced that we had identified a barrier to delivering our proposed funding approach for the NIC in the gas sector. We are working with the Department of Energy and Climate Change (DECC) to resolve this issue at the earliest opportunity. However, it currently appears unlikely that the first Gas NIC will be able to commence in April 2013. We are consulting on proposals to deal with this issue as part of this consultation (see paragraphs 4.21 – 4.30 below).

Innovation in NGET's plan

Our Initial Proposals

4.6. Our Initial Proposals are that NGET's network innovation allowance (NIA) should be set at 0.6 per cent allowed annual revenue. NGET should be able to utilise both the NIC and IRM mechanisms.

Assessment of NGET's proposals

Coverage of innovation in the plan

4.7. In our initial assessment of NGET's July 2011 business plan we observed that while there were some innovative aspects in the plan, it did not demonstrate innovation throughout the business. The March 2012 plan shows a marked improvement. NGET highlights innovative aspects in most of the activities discussed in the plan. The company has adopted a clear approach to labelling this using 'light bulbs'.

[28] The innovation strategy would not give regulatory approval for any specific project. Rather projects will need to meet the requirements of the NIC and NIA governance arrangements – which are being developed through the course of 2012.

4.8. There could be further detail on how, through its innovation, it would be able to do more and/or reduce costs to the consumer. Some of the definitions of innovation were also very wide (though it is right not to limit this to research and development expenditure).

Innovation strategy and NIA

4.9. NGET submitted an innovation strategy as part of its updated plan.

4.10. NGET's strategy set out: its high-level view on the requirement to innovate; the challenges that it will seek to innovate around; the process it uses to try to continually capture and prioritise innovation opportunities; and the process that it will follow to collaborate with 3rd parties.

4.11. NGET requested an innovation allowance of a maximum of 1 per cent of allowed revenue per annum. It recognised that this is higher than the default 0.5 per cent set out in our Strategy Document. NGET justified its proposed higher level by explaining that that the innovation allowance will give them the scope to achieve the efficiency targets that they have included in their plan. NGET also justified this level of funding by citing guidance from various bodies' on the level of innovation spending that is appropriate for utilities.

Our Assessment

4.12. We note the significant improvements in NGET's innovation strategy between July 2011 and March 2012.

4.13. With regard to NGET's justification for additional funding, we note the importance of considering the overall support provided by the innovation stimulus package (NIC, NIA and IRM), together with the opportunities which companies have to fund innovation activities through other revenues. Such funding is also supported by the enhanced incentives which the RIIO framework provides. Taken together we consider this provides a strong package focused on delivering the transition to the low carbon economy while at the same time providing value to consumers. We consider that the base level of NIA funding provides a considerable stimulus for the companies alongside these other incentives. NGET needed to make a clear justification around the additional value that would be delivered by a request for further funding.

4.14. However, there remain some issues with NGET's innovation strategy. For instance: there is a lack of specificity in the stakeholder engagement it has used to support their innovation strategy and priorities; it has not delineated between innovations that they will take forward as part of business as usual versus those which will be funded through specific allowances; and it has not set out what additional value funding above the default would provide.

4.15. We do not consider that NGET has provided sufficient justification for its proposed additional allowance. We need to be satisfied that an additional allowance will provide clearly defined additional value to existing and future consumers. For example, NGET do not explain how a financial evaluation of projects will take place during project implementation. However, on balance, we do consider that the strategy warrants some funding of above the default level. As such, we are proposing a NIA value of 0.6 per cent.

Innovation in NGGT's plan

Our Initial Proposals

4.16. Our Initial Proposals are that NGGT's IA should be set at 0.6 per cent of allowed annual revenue. NGGT should be able to utilise both the NIC and IRM mechanisms.

Assessment of NGGT's proposals

Coverage of innovation in the plan

4.17. In our initial assessment of NGGT's July 2011 business plan we observed that there were some innovative aspects in the plan. However, the plan did not demonstrate innovation throughout the business. The March 2012 plan shows an improvement though not as marked as NGET. NGGT highlights innovative aspects across the plan. The company has adopted the same clear approach to labelling this using 'light bulbs'.

4.18. There could be further detail on how, through its innovation, it would be able to do more and/or reduce the costs to consumers. Some of the definitions of innovation were also very wide (though it is right not to limit this to research and development expenditure).

Innovation strategy and NIA

4.19. NGGT adopts the same approach as NGET to the coverage of innovation in its plan. Its coverage of innovation has also improved since its previous plan and it has the same strengths as NGET; NGGT has clearly set out the challenges that it will seek to innovate around and how it will collaborate with 3rd parties in developing innovations. However, it also has the same weaknesses, namely a lack of specificity in the stakeholder engagement it has used to support the development of its innovation strategy and priorities and a failure to delineate between innovations that it will take forward as part of business as usual versus that which will be funded through the specific NIA.

4.20. NGGT has also published an updated innovation strategy. NGGT requested an innovation allowance of 1 per cent of allowed revenue. We do not consider NGGT has provided sufficient justification to merit this level of allowance. However, it has met the basic requirements set out in our Strategy Document and exceeded these in the same areas as NGET. On this basis, we also propose to provide NGGT an allowance of 0.6 per cent.

Other issues

Delay to the Gas NIC

4.21. In our Strategy Document, we decided to introduce the NIC to provide funding for projects that would contribute to a low carbon energy sector or provide environmental benefits. We decided to set the maximum available funding for gas distribution and transmission at £20 million per year.

4.22. We set out in our Strategy Document that, in implementing the NIC, we intended to replicate the Low Carbon Networks Fund (LCN fund) introduced for the most recent Distribution Price Control Review (DPCR5). This would involve the transfer of funds from all gas licensees to those licensees who win funding through the NIC. We set out in March 2011[29] that we had identified a barrier to delivering this proposed funding approach in the gas sector.

4.23. The Gas Act 1986 allows the Authority to insert provisions into the Gas Transporter licence that require a Gas Transporter to increase its charges to raise such amounts as may be determined and then pay those amounts to gas suppliers and gas shippers. It does not, however, allow the Authority to insert provisions into the licence for the raising and paying of amounts to other Gas Transporters. This differs from the framework in the Electricity Act 1989 which allows for the raising and paying of amounts to all electricity licence holders.[30]

4.24. Our view is that, as drafted, the Gas Act does not allow us to implement the NIC in the gas sector using the mechanism used in the LCN Fund (ie establish the competition for Gas Transporters). We have raised this issue with DECC and we are seeking to find a solution at the earliest opportunity. DECC is actively considering the options for proposing an amendment to primary legislation. However, it currently appears unlikely that a legislative amendment could be provided in time for the start of the first Gas NIC, which is due to commence in April 2013.

4.25. We have therefore identified two options to address the absence of NIC in at least the first year of RIIO-GD1 and RIIO-T1:

[29] Decisions on the Network Innovation Competition and timing and next steps for implementing the Innovation Stimulus. (Ref 34/12).

[30] This issue in relation to GT-GT transfers has arisen because before 2004 there was only one gas transportation company (National Grid Gas) and therefore no need to consider the transfer of monies between several transportation companies. When the gas grid was split between different gas transportation companies, the Gas Act 1986 was amended, but ambiguity remains.

- *Option 1*: Run the NIC and raise the required funds from the winning licensees' customers (i.e. this could be from either NGGT's or a GDN's customers).[31]

- *Option 2*: No NIC in 2013, and no replacement funding in that year. The lost funds would be rolled-over into subsequent years such that the overall level of funding for the Gas NIC (in RIIO-GD1 and RIIO-T1) is unchanged.

4.26. The disadvantage of option 1 is that the costs of a winning project would be borne by GDNs' own customers, i.e. there is no socialisation of costs, whereas the benefits will accrue to all customers. The project costs are potentially a material element of GDNs' total allowed revenues. For example, if a typical GDN (with allowed revenues of around £250 million) were to secure funding for a project of say £15 million (towards the upper-end of funding under LCNF), this could result in an increase in charges of around 6 per cent. Given the impact of winning a project on their customer's charges, together with the socialisation of learning, could discourage participation in the competition by companies.

4.27. The Option 1 approach would also prevent any independents from entering the competition – since their customers could not be expected to fund such projects in the absence of socialisation.

4.28. For these reasons we prefer Option 2. Under this option, we would effectively provide the same level of funding as envisaged in our Strategy Document but over a shorter 7 year period, ie from 2014/15 onwards.

4.29. However, if the NIC is delayed for more than one year, our preference is likely to be for option 1. In such circumstances, we consider it is more important to run NIC and raise funds from the winning licensees customers (and accept no socialisation of costs) than to delay NIC further (and potentially indefinitely).

4.30. At Final Proposals, we should have greater certainty over the prospects of an amendment to primary legislation, and thus whether the delay to NIC is likely to be one year (in which case, we support option 2) or longer (in which case we support option 1). We would welcome respondents' views on our preferred options.

SO Access to Innovation Funding

4.31. Both NGGT and NGET considered that funding should be available to the SO, as well as the TO, through the new mechanisms introduced by RIIO-T1. It therefore considers that the SO should be able to participate in the NIA and NIC.

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[31] Given charges would be raised locally, under this option it would be essential for the winning licensee to demonstrate the benefits of their project for their customers (eg distribution customers), as opposed to gas network customers more widely.

4.32. It is our Initial Proposal that NGET or NGGT should be able to access the TO innovation funding, under the same mechanism, in relation to innovations across both SO and TO activities.

Appendix 1: Progress on network access policy development and customer satisfaction outputs - Update

Appendix Summary

This Appendix provides an update on the joint work that NGET, SPTL and SHETL have been undertaking to develop the arrangements to facilitate SO:TO co-operation in relation to network availability. It also updates on the development of customer satisfaction surveys as part of the implementation of the customer satisfaction outputs for NGET, NGGT, SPTL and SHETL.

Introduction

1.1. There are two outputs where NGET, in its capacity as both a TO and as the electricity SO (along with NGGT in the second case), continues to work with SPTL and SHETL to develop the detail of the arrangements for RIIO-T1. These are the work to develop and implement:

- a network access (formerly referred to as network availability) policy (NAP)
- a customer/stakeholder satisfaction survey as set out in our Strategy Document.

1.2. Both were highlighted in our Initial and Final Proposals for SPTL and SHETL as areas for ongoing work. As we reported then, good progress had been made. This Appendix updates on progress made and maps out next steps.

Network Access Policy (NAP)

1.3. A TO's actions impact on the level of its network available for use, as do a number of other things. Some of the costs associated with the network not being available impact directly on the TOs eg through the reliability outputs discussed in Chapter 2 of this document and the equivalent provisions for SPTL and SHETL. However, the costs of network constraints affect the SO in the first instance. The SO faces separate external incentives on its costs in this area. However, particularly where the SO and TO are separate companies, as is the case in Scotland, the ability of the SO to manage these constraint costs is more limited.

1.4. As with other features of the SO:TO relationship, the SO:TO Code (STC)[32] sets out arrangements to help aid communication and co-operation. However, in setting the new RIIO outputs-based approach to both TOs and to the SO (through the SO from 2013 incentives work) we have tried to encourage the companies to consider how they could go further than these minimum arrangements particularly against the backdrop of significant TO investment over the RIIO-T1 period.

1.5. Before reaching our strategy decision in this area, we consulted on two models for holding the TOs and SO accountable for constraint costs. One was to place a direct financial incentive on the TOs. However, the absence of information available to TOs on constraints costs made an effective incentive impossible to implement. Our strategy decision was therefore to take forward a second option. This had three elements:

- SO faces sharper incentives on constraints management
- TOs have clear baseline level of performance on network availability that would be described in a policy document referred to in their licence
- SO has ability to incentivise TO to change plans in a way that lessens constraint costs (the incentive payment providing recompense from the impact on TO costs).

1.6. In theory, the above option had the advantage that limited change was needed in the information that the SO made available about constraint costs. However, two things became clear as a result of the business plans submitted by the TOs and subsequent discussions. Firstly, the significant investment plans and new outputs regime meant that some of the costs facing the TOs for changing their planned outages are likely to increase significantly for RIIO-T1 compared to the previous control period. Secondly, the causes of constraints on the networks and resulting costs are sufficiently complex to make it impossible for a single baseline level of performance to be identified. In addition, our initial proposals for SO incentives from 2013 include the removal of short-term financial incentives based on detailed models in favour of a broader incentive approach that is designed to encourage more innovative behaviour.

1.7. SPTL, SHETL and NGET representatives have subsequently met on a number of occasions to develop the NAPs beyond what was in the business plans.

1.8. These meetings have focused on:

- Information that might be shared.
- TO priorities.

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[32] **(see http://www.nationalgrid.com/uk/Electricity/Codes/sotocode/Library/)**

- Long-term planning and options for co-ordination.
- Short-term planning and options for co-ordination.

1.9. The companies are meeting in August and will continue to work beyond this. We would expect to be able to consult on draft NAPs with our Autumn 2012 consultation.

Customer satisfaction and stakeholder engagement

1.10. As set out in Chapter 2 and 3 of this document and as set out in the final proposals document for SHETL and SPTL, the customer satisfaction output has two incentive elements. One of these is a +/- 1 per cent of that year's allowed revenue informed by the results of a survey (though likely to involve other supporting information to validate and measure related aspects of performance). The other is a discretionary reward for exceptional outcomes being generated through stakeholder engagement (0.5 per cent of the same measure – upside only).

1.11. National Grid has recent direct experience of surveying its customers and all the companies have carried out a good deal of stakeholder engagement as part of RIIO-T1. However, in all cases the development of a survey and supporting information that we and the companies can be confident provides a realistic appraisal of their performance is a challenge. The companies have worked together on this.

1.12. This part of the Appendix provides an update to stakeholders on progress made and the next steps.

1.13. We intend this output and incentive to reflect the whole range of the companies' performance including particularly aspects that are not easy to define in the other outputs and incentives. This means that we want to understand the views of all customers and stakeholders across the whole range of activities that the company takes part in. However, these two dimensions necessarily differ between National Grid's TOs and the Scottish TOs because of their different roles.

1.14. NGET and NGGT will employ a survey of the views of customers and stakeholders. This will include customers such as developers seeking connection and stakeholders such as interested parties about the development of transmission infrastructure. SPTL's and SHETL's survey will be a stakeholder survey. This recognises that in many activities National Grid as SO has the direct customer interface. Some of SPTL's and SHETL's stakeholder respondents will coincide with NGET customers.

1.15. NGET and NGGT's previous survey experience provides greater certainty about the likely range of responses to normal levels of performance. This is likely to allow the full incentive to be applied with a robust baseline from 1 April 2013. To make this possible we will consult on the proposed model and baseline with our Autumn licence modifications consultation.

1.16. The stakeholder element of NGET/NGGT's survey and SPTL's and SHETL's surveys which are almost wholly reliant on stakeholder responses, means potentially greater variability of response and uncertainty about the survey results (at least initially). The companies are carrying out preparatory work in this area with stakeholders. This will help understand what matters to them and provide more information about the survey results.

In this area supporting information separate to the quantitative survey results will be important and this is another area being progressed. At present our expectation is that we will be able to consult on proposals covering each TO to start in 1 April 2013 although at this stage it seems likely that the incentive will need to be dampened at least initially. It also seems likely that the provisions may need to be updated

National Grid Electricity Transmission

Our performance

2016/17

Welcome

Executive Summary from Nicola Shaw, Executive Director

We are proud to report that our Electricity Transmission business has continued to perform strongly for consumers by delivering **safe, efficient and reliable** transmission services throughout 2016/17. Our ongoing focus on innovation has ensured we have continued to benefit current and future customers.

We are in the middle of a transformation to a low carbon energy system and 2016/17 has seen a number of firsts underlining this. These include the first working day of operation without coal fired generation since the industrial revolution, and record levels of embedded generation connected to the electricity system – with an additional 14.6GW connecting in less than 5 years. We have risen to the network and system operation challenges it presents, and continue to drive down costs whilst delivering excellent **network reliability.**

We continue to invest efficiently in the network to connect our customers; including renewable, low carbon, generation. We are confident that we are on the right trajectory to deliver our network replacement output measures by the end of the RIIO-T1 period, and we are delivering benefits of efficiency strategies. These benefits lead to lower costs for the completed work.

This investment will help secure continued long term system reliability and **keep bills lower** for customers in the future. We have recognised the current pressure on energy consumer bills and in reviewing our investment plans identified a number of investments that had moved into future periods, and as a result voluntarily deferred **£590m**[1] of allowances out of the RIIO-T1 period.

We have continued to deliver strongly on our five primary RIIO outputs:

Safety: We were all reminded of the importance of safety this year, following a tragic incident in which one of our UK employees lost his life. There are always things to do to improve in this sphere and we keep working hard to do so.

Reliability & availability: Our network continued to deliver exceptionally high levels of reliability of 99.999964% in 2016/17 providing our customers with excellent security of supply.

Customer satisfaction: We are listening to what our customers and stakeholders are telling us and changing the way that we work to meet their needs. In 2016 we began a UK-wide customer transformation programme which focuses on putting customer experience at the heart of our business and equipping our employees with the tools, training and information they need to enable them to improve the way we ultimately serve our customers and stakeholders.

Connections: We have delivered all the customer connection outputs required in 2016/17 on time.

Environment: We have continued with our programme to replace and repair equipment leaking SF6 insulating gas (which is harmful to the environment) and we have

[1] £480m in 09/10 price base

reduced forecast leakage rates by over 1000kg. We also won the 2017 ‘Business in the Community Award for Environmental Leadership’ for reducing the CO2 emissions associated with construction projects.

We have delivered these key outputs at a lower cost to consumers. We have done this by driving efficiencies in our plan, challenging how we are delivering the scope of the output and driving down costs in our supply chain. Approximately £774m of savings will be passed on to consumers’ bills through lower network costs.

Following discussions with the Government and Ofgem, and an industry consultation, we have issued a joint statement setting out our timeline for the greater separation of the electricity system operator (ESO) function within National Grid. The ESO will be independent of the transmission business by April 2019 and we have begun to set out how our future system operator role might develop to deliver for the needs of our future customers. Transforming our balancing markets and governance, thinking across transmission and distribution networks and facilitating new markets against a backdrop of becoming more independent are our focus areas.

I hope that you find this booklet informative and helpful. If you have any questions or feedback, please use the links at the end of this report to get in touch.

Nicola Shaw
Executive Director, UK

Content/output area	Highlights	Page
Who we are and RIIO fundamentals	Own and operate over 14000km of overhead lines, 300 substations, and 650km of underground cable. RIIO is Revenue = Incentives + Innovation + Outputs.	4-5
Performance scorecard	Successful delivery of all annual outputs, though some incentive output performance slightly worsened. Uncertainty mechanisms delivering lower volumes than originally forecast.	6-7
Incentives	Strong performance in system reliability, reduction in rewards for customer satisfaction, and environmental incentives.	8-9
Innovation	Good progress in both large scale schemes like at Deeside and an increase in the volume of smaller schemes delivering new technologies.	10-11
Uncertainty Mechanisms	Generation and demand mechanisms broadly working as expected; though at lower volumes than original business plan. Wider works outputs remain uncertain in terms of which schemes may progress.	12-13
Revenue and the domestic electricity bill	We forecast to spend less than forecast allowances. Savings will be shared with customer. Overall cost of our network charges has increased and is £26.16 of the average annual domestic electricity bill.	14-18

Who we are and what we do

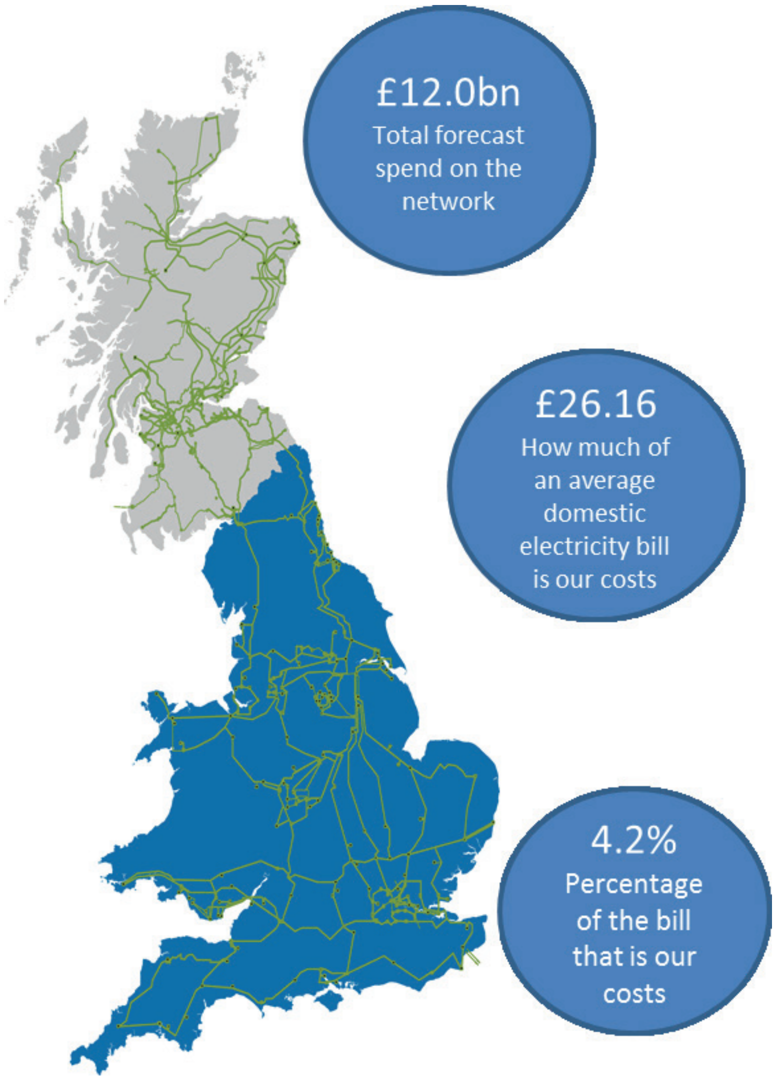
We are a Transmission Owner (TO) and a System Operator (SO). This means that National Grid Electricity Transmission (NGET) owns the electricity transmission network in England and Wales – that's the high-voltage network connecting electricity generators to distribution networks and large-scale consumers. We also operate Great Britain's entire electricity transmission system, including the Scottish and offshore networks.

Our role is to connect people to the energy they use – whether it's heat and light for their homes or to keep factories and offices running. As society continues to become ever more reliant on electricity for every aspect of modern life, we have a central role to play in meeting one of Britain's biggest challenges: providing secure and affordable energy while also meeting ambitious low-carbon energy targets and connecting new sources of energy to the people who use them.

The unprecedented rate of change in the energy landscape means we have to be adaptable and responsive. That's why we invest efficiently to provide world-class reliability and to enable customers to connect to the network.
We also promote the development and implementation of sustainable, innovative and economical energy solutions that will help us achieve security of supply.

At the heart of our business plan is the delivery of an affordable electricity transmission network that meets our stakeholders' needs in terms of energy security and environmental considerations.

Over the next decade we expect to continue our work to modernise the country's energy infrastructure.
We know that building new assets or refurbishing existing ones has an impact on our customers and stakeholders and so we believe the best way forward is to involve them as early as possible in the decision-making process.



Fundamentals of RIIO – Revenue = Incentives + Innovation + Outputs

RIIO introduced a range of new principles that are relevant to our performance

RIIO-T1 started in 2013/14 and lasts for eight years. Under this regulatory framework we have a set of outputs to deliver that we have agreed with stakeholders. We deliver these outputs efficiently in return for an efficient revenue allowance that we have been set by our regulator Ofgem. RIIO also introduced a range of new principles which drive our performance, so we've outlined them below.

Risks and benefits are shared with customers

One of the principles of the RIIO framework is to align the interests of National Grid with those of consumers through the sharing of risks and benefits. This means that, for every pound we save, 53p of the benefit is passed on to end consumers through lower network charges. This ensures National Grid is driven to find efficiencies to reduce costs and consumers benefit in both the short and long term.

Incentives are encouraging better ways of working

We are encouraged to improve across different areas of our operations through a range of incentives agreed as part of the RIIO framework. For instance, customers and stakeholders want us to improve how we work with them and we receive rewards or penalties depending on how we perform. There are other incentives to improve our environmental performance (SF6 leakage) and the reliability of our supply to the distribution networks and other customers. We are changing the way that we work to meet the outputs that our stakeholders tell us are important to them.

Finding a better way in everything we do

The RIIO framework provides a stimulus package to support innovation: the Network Innovation Allowance (NIA); the Network Innovation Competition (NIC); and the Innovation Roll-out Mechanism (IRM). Innovation is not only at the heart of the RIIO regulatory framework but also at the heart of everything that we do.
There are many examples where we have identified improvements as a result of one of the innovation funds are exploring and driving benefits for consumers through innovation projects.

Flexible and fixed allowances

In some areas (like connecting customers to the electricity system) the future costs to be incurred and outputs to be delivered over the current RIIO period were uncertain and expected to evolve. So our allowances flex using an "uncertainty mechanism" reflecting changing customer requirements. There's also an allowance for the maintenance and asset replacement work that's needed in order to continue to provide a safe and available electricity network, and to keep the current level of network reliability. On the next two pages you can see our overall in year performance across all of the five output areas.

Performance Scorecard

This information includes incentives, uncertainty mechanisms, reopener submissions and ex-ante allowances. To help, the performance is coloured coded as per the key below.

Red - An annual output that has been missed and forecast to miss our 8-year output.

Amber - An annual output that has been missed but is on target to achieve our 8-year output. Or the achievement of annual output but is at risk of failure for our 8-year output.

Green - Achievement of an annual output and on-target to meet our 8-year output.

Grey - An "uncertainty mechanism" where there was an agreed baseline forecast of annual outputs but we have not delivered the baseline due to our customers' requirements changing over time.

Output requirement	RIIO measure	2016/17 Performance
Safety		
Comply with Health & Safety Executive (HSE) law We continually review our processes to try to reduce the risk of accidents to the public, our staff, and our contractors. We were all reminded of the importance of safety this year, following a tragic incident in which one of our UK employees lost his life. Our injury frequency rate (an industry standard measure of safety) rose slightly to 0.13. We are redoubling our efforts to reduce this measure.	To meet all safety legislation requirements	**All met**
Reliability and availability		
Minimise how much electricity is lost to our customers because of failures of the assets on our network The third year in a row where we have had less 10MWh of interruptions to our customers' service. This equates to 99.999964% availability of our network.	Neutral point at 316MWh p.a.	**6.8MWh**
Non load related network replacement outputs There has been a threefold increase in output delivery in 2016/17 compared to last year. We are on track to have the agreed level of network risk remaining on the system at the end of RIIO-T1 for all but one of the measures. In addition we are delivering this for less cost than our allowances and so are sharing the savings with customers.	Compliant with network risk level at end of RIIO	**Lower spend and volumes than at this stage in original business plan. On track for the full price control.**
Protect our critical assets to minimise disruption (physical security) We're working hard to deliver the programme submitted in 2015 for the allowances that were agreed. We've reprogrammed work leading to lower costs in 16/17 and new contracting strategies will reduce costs in future.	£11m totex allowance	**£7.1m totex spend**
Incremental Wider Works (IWW) to strengthen specific boundaries Two IWW schemes were due to complete in 16/17, but both have been delayed due to changing customer requirements and are not required at present.	3850MW	**0MW**
Forecast the amount of wind generation produced £3m annual cap and collar incentive based on accuracy of forecasting of renewable generation. Our accuracy improved in 16/17 compared to previous years but narrowly missed neutral point resulting in a £67k loss.	+/- 3.5% and +/- 4.25 accuracy in summer/winter	**3.86% in summer 4.28% in winter**
Balance the supply and demand on the transmission system The System Operator has a number of products and services that it can procure in order to balance the electricity network. Good balancing performance has led to £17.5m to be shared between NG (£5.3m) and customers (£12.2m)	Target spend £963.5m	**Actual spend was £945.8m**

Environmental benefits		
Minimise greenhouse gas emissions, especially SF6 Neutral point is 1.48% leakage rate and the 2016/17 performance was 1.31%. This performance was slightly worse than last year due in part to a failure of a single circuit breaker asset. However, this performance is still over 20% ahead of the baseline forecasts. Efforts to find innovative leak repairs and other ways of reducing leakage continue to be developed.	Neutral point of 12,242kg of SF6 top-ups	**10795kg topped up**
Going above and beyond to deliver low carbon solutions Environmental Discretionary Reward panel meeting to discuss our submission will be held on the 12th October 2017. During this discussion we will be informed of the reward outcome. One of the great successes in the year was winning industry awards for our focus on reducing the emissions associated with construction projects which we have used at Wimbledon substation.	50-70% is proactive 70%+ is leadership	**Scored in 50-70% range in 2015/16 Results due 12th October for 2016/17 submission**
Customer satisfaction		
Measure the way that we have satisfied our customers and stakeholders We carry out surveys with our customers and stakeholders which gives and annual score of their overall satisfaction with the way that we deal with them. Our customer satisfaction reduced slightly and we are working closely with customers to understand how we can improve the service to them.	Neutral point at Customer 6.9/10 Stakeholder 7.4/10	**Score out of 10** **7.41** **7.66**
Go above and beyond in the way we engage with our stakeholders This result was the highest score that we have received for the Stakeholder Engagement Incentive Scheme and reflects positively on the work that we are doing to keep customers and stakeholders at the heart of all that we do.	Neutral point at 4.0/10	**7.0**
Customer connections		
Send customer offers within 90 days We sent all new or modified offers to customers within the 90 days and have changed our processes to include the customer much more in the offer development process.	100%	**100%**
Connect new generation customers to our network We delivered all our customers' capacity requirements for 2016/17 but this was lower than the original baseline. Our 8-year forecast, based on customer needs, is for 10.5W of transmission connected generation (original business plan (OPB): 26GW), a decrease of 3.4GW on 2015/16.	3553MW 100km OHL	**1261 MW No new OHL**
Connect new demand customers onto the network We delivered all of the demand connection requirements that our customers contracted us to complete. This volume was lower than the baseline amount. We forecast that we will need to connect 52 new super grid transformers (OPB 72) and 5km of OHL (OPB: 27km) for demand customers.	9 SGTs 3km OHL	**3 SGTs No new OHL**

Incentive performance

Reliability

The incentive output that measures our system's reliability is the Energy Not Supplied (ENS) incentive. The total incentivised energy not supplied in 2016/17 was 6.8 MWh compared with the neutral point of 316 MWh. The table below shows that there was a total unsupplied energy of 89.3 MWh. However, two events were excluded from the ENS, one due to the type of contract a customer has, and in the other the duration of the loss of supply was less than three minutes.

Energy not supplied (ENS)	2013/14	2014/15	2015/16	2016/17
Volume of unsupplied energy	135.9	9.8	4.5	89.3
Volume of unsupplied energy from excluded incidents	0.9	1.1	0.0	82.5
Volume of unsupplied energy in Incentivised Events	**135.0**	**8.7**	**4.5**	**6.8**
Neutral point (in MWh)	316.0	316.0	316.0	316.0
Difference (in MWh)	**(181.0)**	**(307.3)**	**(311.5)**	**(309.2)**

Customer

Increasing our focus on customers and stakeholders, and better meeting their requirements, is one of our main priorities. We are rolling out a number of initiatives to help improve the service and engagement we provide. In 2016 we began a programme focusing on putting the customer experience at the centre of our business and equipping our employees with the tools, training and information they need to improve how we serve our customers and stakeholders.

In 2016/17, we achieved a customer satisfaction score of 7.41 in the survey that is carried out. The stakeholder satisfaction score was 7.66; an improvement since last year.

Each year all the gas and electricity transmission and distribution companies submit an overview of their stakeholder engagement activities held over the previous 12 months, and how these have informed their business plans. At an independent panel, stakeholder engagement experts probe the submissions, asking in-depth questions about the work. We scored 7.0 – an increase of 0.75 against our 2015/16 score. Ofgem's summary feedback from the panel session reflects the improvements we're making in this area.

The table below shows the annual scores in the different incentives that we are measured against.

Customer & Stakeholder Incentives	2013/14	2014/15	2015/16	2016/17
NGET Customer survey – neutral point	6.90	6.90	6.90	6.90
NGET Customer survey – score	7.41	7.40	7.54	7.41
Stakeholder survey – neutral point[2]	N/A	N/A	N/A	7.4
Stakeholder survey - score	7.53	7.74	7.53	7.66
Stakeholder Engagement neutral point	4.0	4.0	4.0	4.0
Stakeholder Engagement Incentive score	5.75	6.0	6.25	7.0

[2] The stakeholder satisfaction survey neutral point was not established until after the first three years of RIIO-T1.

Environment

There are two incentives that reward (or penalise) our efforts to deliver a low carbon future. The SF6 incentive rewards us for topping up less than the neutral point and penalises us if we lose more than this amount of gas from our substation assets. The table below shows how we're doing so far in this price control:

SF6	2013/14	2014/15	2015/16	2016/17
Actual top-ups (kg) (a)	10110	9544	9713	10795
Neutral point (kg) (b)	12037	12139	12199	12242
Business plan forecast (kg)	12950	13370	13830	14310
Difference (kg) (a-b)	1927	2595	2486	1447

For the 2016/17 period, we experienced higher SF6 top-ups than in any previous RIIO reporting year but still leaked less than the forecast published in the RIIO-T1 business plan.

During 2016/17, our worst-leaking asset was repaired and will lead to over 1,000kg reduction in losses annually from mid-March 2017 onwards. During 2017/18 we have planned to include 24 of the top-leaking assets for replacement to improve the leakage performance.

The Environmental Discretionary Reward (EDR) submission has been made to the independent panel for 2016/17, using learning from feedback on the format of our submission in 2015/16 for which we received no incentive reward. The outcome is expected in October 2017. The table below shows our results in first three years of the scheme.

Environmental Discretionary Reward	2014	2015	2016
Strategic understanding and commitment to low carbon objectives	Proactive	Leadership	Leadership
Whole electricity system planning	Proactive	Good evidence	Engaged
Connections for low-carbon generators	Proactive	Good evidence	Engaged
Collaboration on innovation	Proactive	Leadership	Engaged
Network development solutions that avoid the need to reinforce the network	Proactive	Leadership	Not enough evidence
Direct environmental impact	Proactive	Leadership	Leadership
Greenhouse gas emissions	Proactive	Leadership	Not enough evidence
Overall total	**Proactive**[3]	**Leadership**	**Proactive**

[3] <50%=Engaged, 50-69%=Proactive, 70+%=Leadership

Innovation – a summary of innovation projects

The pace of change in the energy industry shows no sign of letting up and we recognise that we have a crucial role to play in making sure Great Britain has a sustainable energy future. Innovation is at the forefront of that challenge.

As part of RIIO, Ofgem introduced two new funding mechanisms for network innovation: the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). Both of these funds enable us to take forward ground-breaking new ideas and technologies that will make a tangible difference to customers and communities.

NIA and NIC tell only part of the innovation story within National Grid; innovation is central to the work we do every day to keep the energy flowing to homes and businesses across Great Britain, to drive down costs, and to improve the service we provide to customers and end consumers. We are finding a better way to improve our internal processes to deliver a better customer experience. We are innovating to understand more about our assets every day, so we know the best time to replace, repair or refurbish them. We are choosing new and innovative ways of delivering the outputs that we have agreed and we are using innovative contracting and procurement methods to reduce costs when we are completing the construction.

Themes for innovation

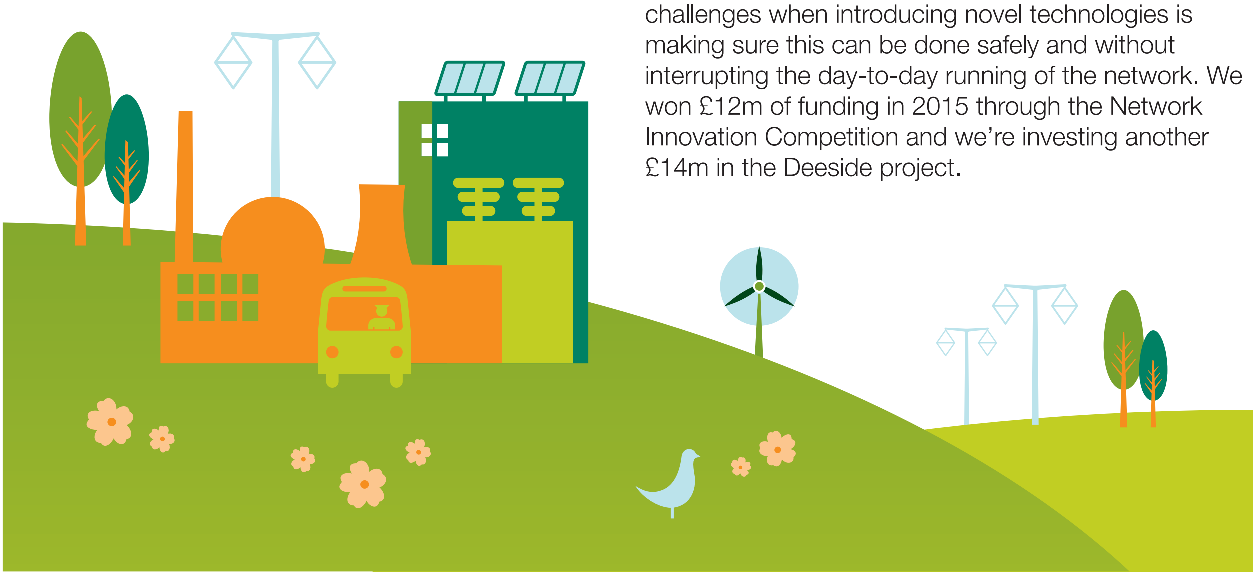
This year we have invested the £6.7 million NIA allowance in 116 projects covering a wide range of network asset and system operation challenges and opportunities. We also enter the Network Innovation Competition (NIC) for our larger innovation activities and look forward to sharing the benefits, including the intellectual property of these schemes with our utility colleagues.

Where we're investing for the future

At our Sellindge substation, we have trialled a novel alternative to SF6 from GE Grid Solutions: g3 (Green Gas for Grid). g3 is a new gas mixture that delivers the same technical benefits as SF6 while reducing the global warming potential ratio from 23,900 to 345, an amazing 98% improvement, saving approximately 40,000tCO2e[4]. This pilot project has stimulated international academic appetite to further progress the SF6-alternative research.

Creating a testbed for technologies

Elsewhere, the development of an innovation centre at Deeside will help us speed up the implementation of new ideas and technologies onto the network. By mirroring a live substation but working off-grid, we can test assets in real life conditions. One of the biggest challenges when introducing novel technologies is making sure this can be done safely and without interrupting the day-to-day running of the network. We won £12m of funding in 2015 through the Network Innovation Competition and we're investing another £14m in the Deeside project.



[4] CO2e is the carbon dioxide equivalent value. For SF6, the multiplier is 23900 to work out the CO2e of this insulating gas

New opportunities from and for distributed generation

The energy landscape across Great Britain continues to change, particularly with the growth of embedded generation. Our portfolio of projects seeks to address these changes and to anticipate the challenges that lie ahead. The Power Potential project is an example of how we're seeking to harness distributed energy sources such as wind turbines and solar panels in a new way.

Together with UK Power Networks (UKPN) we're using £9.5m of innovation funding to explore whether sources of generation connected to the distribution network can be used to provide services such as dynamic voltage control. By 2050, the project could result in cumulative savings for consumers of up to £412m.

Improving solar forecasting

As the amount of solar generation on the network increases, we're also working on a series of projects to help realise the full potential of solar photovoltaic (PV) generation. These projects include collaboration with the Met Office to improve the accuracy of solar forecasts we receive.

There's also a second piece of work with the University of Reading to assess the probability of different weather scenarios and what they might mean for solar PV and wind generation. Meanwhile, the Sheffield Solar project focuses on solar monitoring and is developing a live data feed of national and regional solar generation.

Collaboration is vital

Although technology is a crucial component of our innovation portfolio, the real driving force behind the work is people, and the projects draw on the expertise of colleagues from right across our business. We also reach out beyond National Grid and in the past year we've worked with 55 different suppliers and partners, including universities, distribution network operators (DNOs), equipment manufacturers, tech companies and many others.

Looking ahead, we'll continue to work on the projects that are already under way in close co-operation with our external partners. Later this year, with the support of the Energy Networks Association (ENA), we and the other GB electricity networks will prepare an electricity networks innovation strategy.

Find out more about our pioneering innovation work by downloading the NGET Innovation Annual Summary[5]

[5] http://www2.nationalgrid.com/Annual-Summaries.aspx

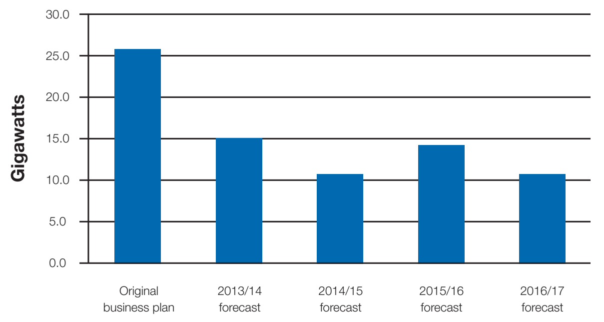
Uncertainty Mechanisms

In the price control it was agreed that a number of outputs could be described but the volumes, and indeed timing, were less certain given how far into the future they were. The RIIO framework allows for a flexing of our allowances as these uncertainty mechanisms flex depending on the volume of output.

For instance, connecting new generation had a baseline of 33GW (original business plan (OBP) submission forecast 26GW) and 216ckm of OHL and a unit cost allowance (UCA) of £27.0/kW and £1.1m per circuit km of OHL respectively. Our current capital plan delivers generation outputs for £28.3/kW (in 2009/10 prices), which is largely unchanged from last year's average. This shows the uncertainty mechanism is working as intended even though the volume of new generation has significantly reduced to an 8-year forecast of 10.5GW. The unit cost of connecting new generation varies from project to project, dependent upon the size and location of the generation in question. For example, one connection requires a new 400kV substation to be constructed and the extension of another, the construction of a new OHL between these substations, works on existing circuits, and the extension of an operational tripping scheme. Conversely, the use of existing capacity on the network can be utilised to provide a less costly solution. For example, another connection utilises an existing bay in a substation, lowering the overall cost of delivering the connection.

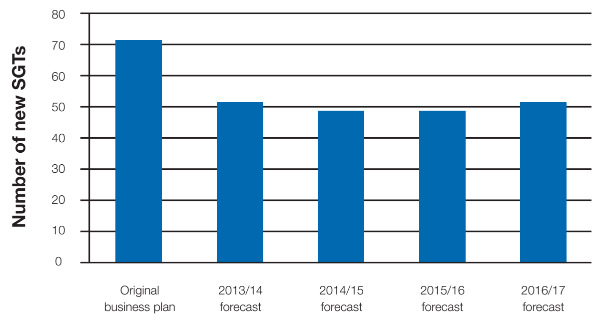
It should be noted that while the anticipated volume of transmission connected generation has fallen, the level of embedded generation connecting to the transmission and distribution systems remains high. In the last four years, 14.6GW of embedded generation has connected, with approximately another 8.8GW anticipated in the remainder of RIIO-T1. This may necessitate additional investment in shunt reactors and / or other transmission solutions that are not funded through the uncertainty mechanisms.

8 year view of new generation connection (GW)

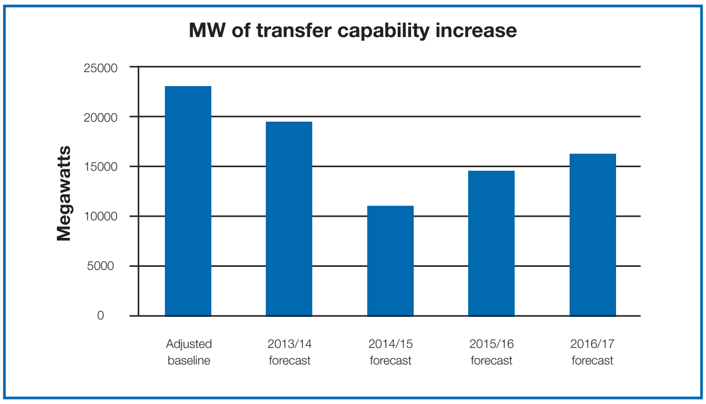


For connecting customers to facilitate increases and changes to electricity demand, there was a baseline of 72 new SGTs with a unit cost allowance of £3.9m per new transformer and associated substation works, and 27 circuit km of overhead line for £1.1m/circuit km unit cost allowance. The cost of providing infrastructure to facilitate new demand connections also varies in a similar manner to that for generation. Our current capital plan delivers demand outputs for £4.4m/SGT (in 2009/10 prices), which is lower than our forecast last year (£4.5m/SGT, 09/10 prices) and is higher than the unit cost allowance.

8 year view of new Demand Connection (SGTs)



A third area of uncertainty was for reinforcing the network to allow safe and reliable flow of electricity due to wider changes in generation and demand. Wider works UCAs were developed using the cost of investments identified based in our business plan. Each year, the Network Outputs Assessment (NOA) looks at all of the inputs (customer requirements, timing, network topology etc.) and gives the least worst regret cost benefit analysis which leads to different solutions (based on the most up to date information) being recommended. Occasionally schemes are recommended that are significantly lower cost than the original baseline schemes. This is mainly due to the inputs detailed above.



Baseline and strategic wider works

During RIIO there have been c£145m (16/17 prices) costs incurred on three potential strategic wider works (SWW) schemes; Hinkley Point C, North West Coast Connection (NWCC) at Moorside, and Horizon Nuclear at Wylfa. The progression and timing of these new nuclear power stations remains challenging to determine. Within our investment plans we have included the works associated with the connection of all three, however, it is likely that not all will proceed in these timescales which would impact spend in RIIO-T1. Given this uncertainty, we are carefully managing expenditure related to these projects.

The SWW final needs case submission for the prospective Hinkley – Seabank project was made in March 2017 and is currently under consideration by Ofgem. This submission reported an estimate of £839m (2016/17 price base) for the SWW elements of the project.

In May 2017, NuGen (the generator at Moorside) announced that, as a result of shareholder and reactor vendor issues, a strategic review of the Moorside project would be undertaken. In light of this, we are pausing all activities as this is in consumers' interest to not to commit spend without certainty of an output being delivered.

Currently the costs on the specified preconstruction schemes in SC3L (Eastern HVDC and Wylfa-Pembroke HVDC) total £1.4m during RIIO. It is likely that only Eastern HVDC will progress preconstruction during RIIO. The table below shows the baseline wider works as shown in the transmission licence in special condition 6I (SC6I).

Project	RIIO-T1 Allowance (09/10 prices)	RIIO-T1 Spend (09/10 prices)	Licence delivery date	Expected delivery date	Complete?
Scottish Series and Shunt	£51.584m	£67.26m	2014/15	2014/15	Yes
Harker – Hutton – Quernmore	£62.227m	£61.48m	2014/15	2014/15	Yes
Penwortham QBs	£4.344m	£12.46m	2014/15	2014/15	Yes
Western Link	£621.1m	£602.37m	2016/17	2017/18	No
Total	**£739.255m**	**£743.57m**			

Across the portfolio of baseline wider works, there has been an overspend compared with allowances. There are a number of reasons for this; additional works required in the Series and Shunt scheme to fix post commissioning faults, and reprofiling of spend in the Penwortham scheme meant that costs were greater than allowances. For the re-conductoring scheme, costs were less than allowances due to efficiencies in contracting and delivery, and for the Western link project we are forecasting to spend less than allowances and will report on the full reasons for this once the scheme is complete.

The Western link joint venture encountered a number of delays in cable manufacturing, installation, and commissioning. In accordance with the mid period review output accountability decision, we will submit a Western Link post commissioning report to Ofgem, within three months of project commissioning. This will detail the steps we have taken in response to the various delays and how we have gone about minimising the impact on consumers. The current completion forecast for delivery remains in the 2017/18 financial year.

Current Year and 8-year view

Across SO and TO, we have driven down costs to £1.28bn in 2016/17 and the RIIO framework provides allowances of £1.45bn. The saving will be shared with our customers. Our overall Totex forecast costs for the RIIO-T1 period are £12.0bn set against adjusted allowances of £13.5bn which is a £1.46bn of savings against allowances, again to be shared with customers. We have saved these costs in a number of ways; from reducing costs in our supply chain to targeting the scope of works that deliver the output, and from bundling schemes to optimise the plan to extending the life of our assets. We have also found savings in how we forecast to reinforce the network based on the latest recommendation of the NOA.

Within this overall forecast, we are to invest £9.0bn Capex over the RIIO-T1 period in order to deliver our load and non-load related plans. This delivery will sustain the current high levels of reliability and resilience into the long term, facilitate new low carbon generation to access the market, connect new load, and keep the total of network and balancing costs low for the benefit of future consumers.

To deliver all of our 'load related' outputs for new connections and associated network reinforcements our capex is forecast, over the 8-years of this price control, to be £3.7bn which is £0.1bn lower than our adjusted allowances. Costs which are currently lower than allowances could change into being higher than allowances if different generators connect and different system reinforcements are triggered than are forecast for the remainder of RIIO-T1.

To deliver 'non-load related' investment to ensure the long term health and reliability of our assets our 8-year capex forecast is to be £4.13bn which is £1.1bn lower than allowances.

SO Opex spend is lower than allowances due to lower Information Systems (IS) support costs and fewer IS projects going ahead than forecast at the start of the period. This underspend against allowances is partially offset by additional spend for some of the new enhanced roles that the SO is carrying out that weren't foreseen at the start of RIIO.

SO Capex spend is slightly higher than allowances because of increased forecast spend to build new data centres to deal with the emerging and dynamic cyber security threats.

Costs and revenue impact – actual revenue vs. allowances for reporting year

We have published below a table showing what we have spent to date and what we forecast to spend in the rest of RIIO-T1 in both the electricity TO and SO businesses. The first part of the table is called total expenditure (Totex) as it includes both our capital expenditure (Capex) and our operational expenditure (Opex)[6].

The next part of the table shows our adjusted allowances[7] for the first three years of RIIO, our forecast allowance for 2016/17, and for the remainder of this price control. The final part of the table shows the difference between costs and adjusted allowances with numbers shown in red meaning costs exceed allowances.

AllowanceActual/Forecast Expenditure (£m, 2016/17 Prices)		Actual	Actual	Actual	RIIO-T1 Forecast					
		2014	2015	2016	2017	2018	2019	2020	2021	Total
TO	Load Related Capex	696.7	537.3	492.2	366.6	387.3	269.4	408.5	551.9	3,709.8
	Asset Replacement Capex	270.2	194.9	223.0	307.4	395.0	432.6	341.1	434.1	2,598.3
	Other Capex	222.5	72.0	157.5	132.9	201.1	385.0	451.1	386.3	2,008.3
	Non Operational Capex	37.3	29.8	38.5	50.4	49.8	30.7	23.3	18.0	227.8
	Total Capex	**1,226.8**	**833.9**	**911.2**	**857.3**	**1,033.2**	**1,117.6**	**1,223.9**	**1,390.3**	**8,594.3**
	Total Controllable Opex	**252.7**	**277.0**	**281.9**	**258.6**	**268.5**	**270.0**	**263.6**	**240.7**	**2,113.1**
TO	**TOTEX**	**1,479.6**	**1,110.9**	**1,193.1**	**1,115.9**	**1,301.7**	**1,387.6**	**1,487.5**	**1,631.1**	**10,707.4**
SO	**Non Operational Capex**	39.6	42.3	41.1	55.3	85.3	68.3	46.2	31.6	409.6
	Controllable Opex	100.7	97.4	101.3	107.1	128.1	122.3	111.3	110.3	878.6
SO	**TOTEX**	**140.3**	**139.7**	**142.3**	**162.5**	**213.4**	**190.6**	**157.5**	**141.9**	**1,288.2**
	TO and SO TOTAL	**1,619.8**	**1,250.6**	**1,335.4**	**1,278.4**	**1,515.1**	**1,578.2**	**1,645.0**	**1,773.0**	**11,995.6**

Total Allowances (£m, 2016/17 Prices)		RIIO-T1 Allowances								
		2014	2015	2016	2017	2018	2019	2020	2021	Total
TO	Load Related Capex	1,040.3	775.3	544.1	388.6	149.4	287.2	340.0	473.1	3,998.0
	Asset Replacement Capex	375.1	385.8	361.9	369.5	475.4	585.9	532.3	430.2	3,516.1
	Other Capex	216.4	210.8	223.3	245.5	332.4	432.6	353.0	324.0	2,338.0
	Non Operational Capex	51.8	48.5	32.0	35.7	34.9	12.4	16.1	14.7	246.2
	Total Capex	**1,683.6**	**1,420.4**	**1,161.3**	**1,039.3**	**992.1**	**1,318.1**	**1,241.3**	**1,242.1**	**10,098.2**
	Total Controllable Opex	**236.1**	**241.2**	**250.4**	**253.5**	**256.3**	**258.0**	**262.2**	**263.0**	**2,020.7**
TO	**TOTEX**	**1,919.6**	**1,661.6**	**1,411.7**	**1,292.8**	**1,248.5**	**1,576.1**	**1,503.6**	**1,505.1**	**12,118.9**
SO	**Non Operational Capex**	63.8	46.3	42.1	42.0	79.2	57.4	44.8	39.4	414.9
	Controllable Opex	**91.0**	**96.6**	**106.4**	**115.9**	**132.8**	**131.5**	**122.3**	**124.2**	**920.7**
SO	**TOTEX**	**154.8**	**142.9**	**148.6**	**157.9**	**211.9**	**188.9**	**167.1**	**163.6**	**1,335.6**
	TO and SO TOTAL	**2,074.4**	**1,804.5**	**1,560.3**	**1,450.7**	**1,460.4**	**1,765.0**	**1,670.6**	**1,668.7**	**13,454.6**

Variance Actual/Forecast v Allowances (£m, 2016/17 Prices)		Variance to Allowance								
		2014	2015	2016	2017	2018	2019	2020	2021	Total
TO	Load Related Capex	343.6	238.0	51.9	22.0	-237.8	17.8	-68.4	-78.8	288.2
	Asset Replacement Capex	104.9	191.0	138.9	62.1	80.4	153.3	191.2	-3.9	917.7
	Other Capex	-6.1	138.8	65.9	112.6	131.3	47.6	-98.2	-62.3	329.6
	Non Operational Capex	14.5	18.7	-6.5	-14.7	-14.9	-18.2	-7.2	-3.3	-31.6
	Total Capex	**456.8**	**586.5**	**250.1**	**182.0**	**-41.0**	**200.5**	**17.4**	**-148.3**	**1,503.9**
	Total Controllable Opex	**-16.7**	**-35.8**	**-31.5**	**-5.1**	**-12.2**	**-12.0**	**-1.4**	**22.3**	**-92.4**
TO	**TOTEX**	**440.1**	**550.7**	**218.6**	**176.9**	**-53.2**	**188.5**	**16.0**	**-126.0**	**1,411.5**
SO	**Non Operational Capex**	24.2	4.0	1.1	-13.4	-6.1	-10.9	-1.4	7.8	**5.3**
	Controllable Opex	**-9.7**	**-0.8**	**5.2**	**8.8**	**4.6**	**9.2**	**11.0**	**13.9**	42.1
SO	**TOTEX**	**14.5**	**3.2**	**6.3**	**-4.6**	**-1.5**	**-1.7**	**9.6**	**21.7**	**47.5**
	TO and SO TOTAL	**454.6**	**553.9**	**224.8**	**172.3**	**-54.7**	**186.8**	**25.6**	**-104.3**	**1,459.0**

[6] Capex is broadly the costs incurred in building new assets and replacing existing ones. Opex is broadly the costs incurred for maintaining the assets and running the National Grid business.

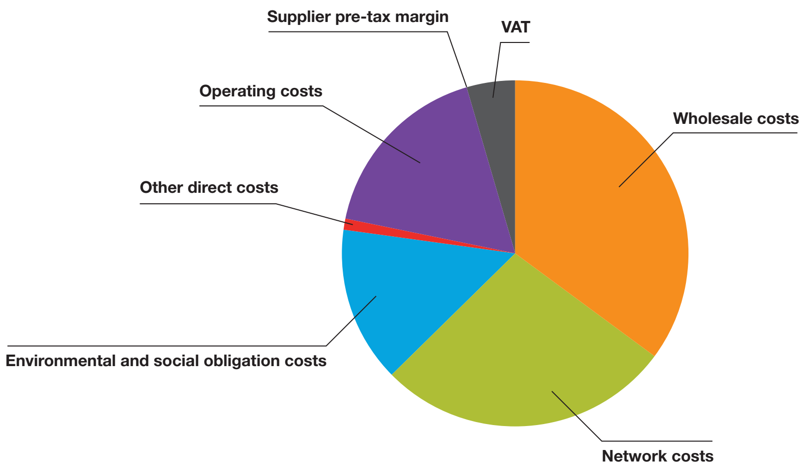
[7] This figure is after the alignments of allowance categorisation to be consistent with treatment of spend. Therefore, in load related capex, this includes the allowance deferral but not the end of RIIO-T1 true up as this is not agreed at present and so is not consistent with numbers quoted in the text.

Consumer bill – how RIIO revenue affects the domestic electricity bill

So what does this mean for the end consumer? Our revenues are recovered through the charging our customers for the services we provide. These network costs for both transmission and distribution make up about 25% of the domestic electricity bill that consumers receive from their supply company.8 Of this total bill only 4.4% is attributed to our TO and SO costs, or approximately 20% of the network costs.

The consumer bill infographic shows the cost of the different parts that make up the average domestic electricity bill. The table below shows our actual and forecast contribution to the customer bill. There is some fluctuation in the total costs because of changes to the timing of our developments, the mid-period review adjustments, and the impact of changes to how much generators pay us to use the system.

Breakdown of an electricity bill



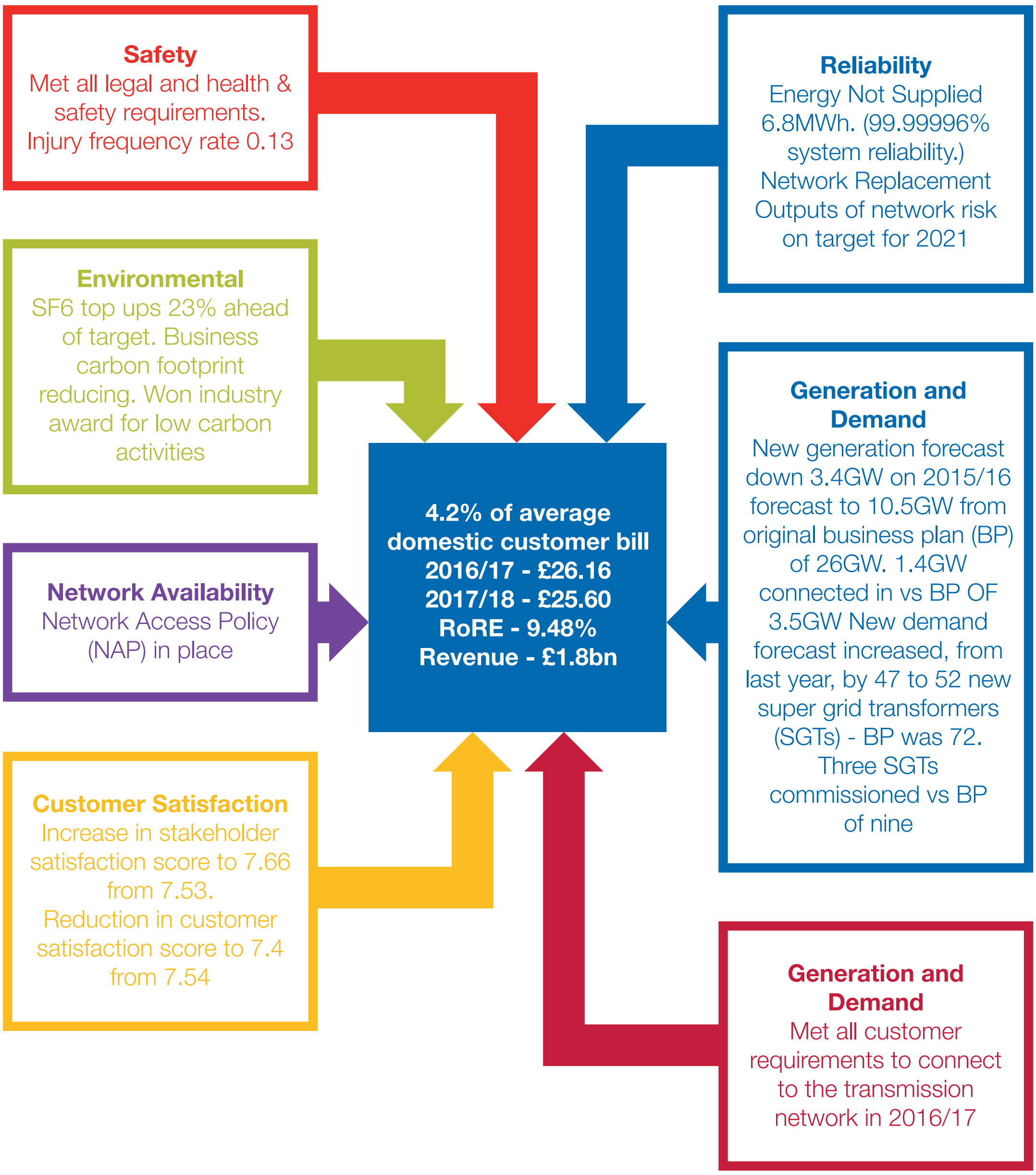
National Grid TO and SO costs in an electricity bill – to date and forecast

Business		2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
National Grid Transmission Owner	£	20.25	22.49	24.96	25.13	24.49	23.70	26.68	30.61
System Operator Internal costs	£	0.92	1.07	1.17	1.03	1.11	1.29	1.32	1.36
TOTAL[9]	£	21.17	23.26	26.14	26.16	25.60	24.98	28.01	31.97
Average domestic electricity bill	£	603	601	596	-	-	-	-	-

[8] Overall network costs account for approximately 25% of the domestic electricity bill, over 20% of which is distribution network costs not transmission
Source https://www.ofgem.gov.uk/information-consumers/domestic-consumers/understanding-energy-bills

[9] There is rounding of both TO and SO costs, but as a total they are correct (2015/16 and 18/19 look 1p out)

Outputs at a glance



How to contact us and other useful links

If you have questions or opinions on this performance summary, please get in touch with us:

by emailing us at **talkingnetworks.transmission@nationalgrid.com** or using the "Have your say" feedback link on our Talking Networks website **www.talkingnetworkstx.com.**

To find out more about customer bills and the impact of network costs, visit **www.ofgem.gov.uk/information-consumers/domestic-consumers/understanding-energy-bills**

For information on our Innovation activities, visit **http://www2.nationalgrid.com/UK/Our-company/Innovation/Electricity-Transmission-Innovation/**

To see how this fits in with how the energy network powers your home, visit **ww.ofgem.gov.uk/network-regulation-riio-model/energy-network-how-it-works-you**

To find out more about our electricity business and the market we operate in, visit **http://media.nationalgrid.com/factsheets/**

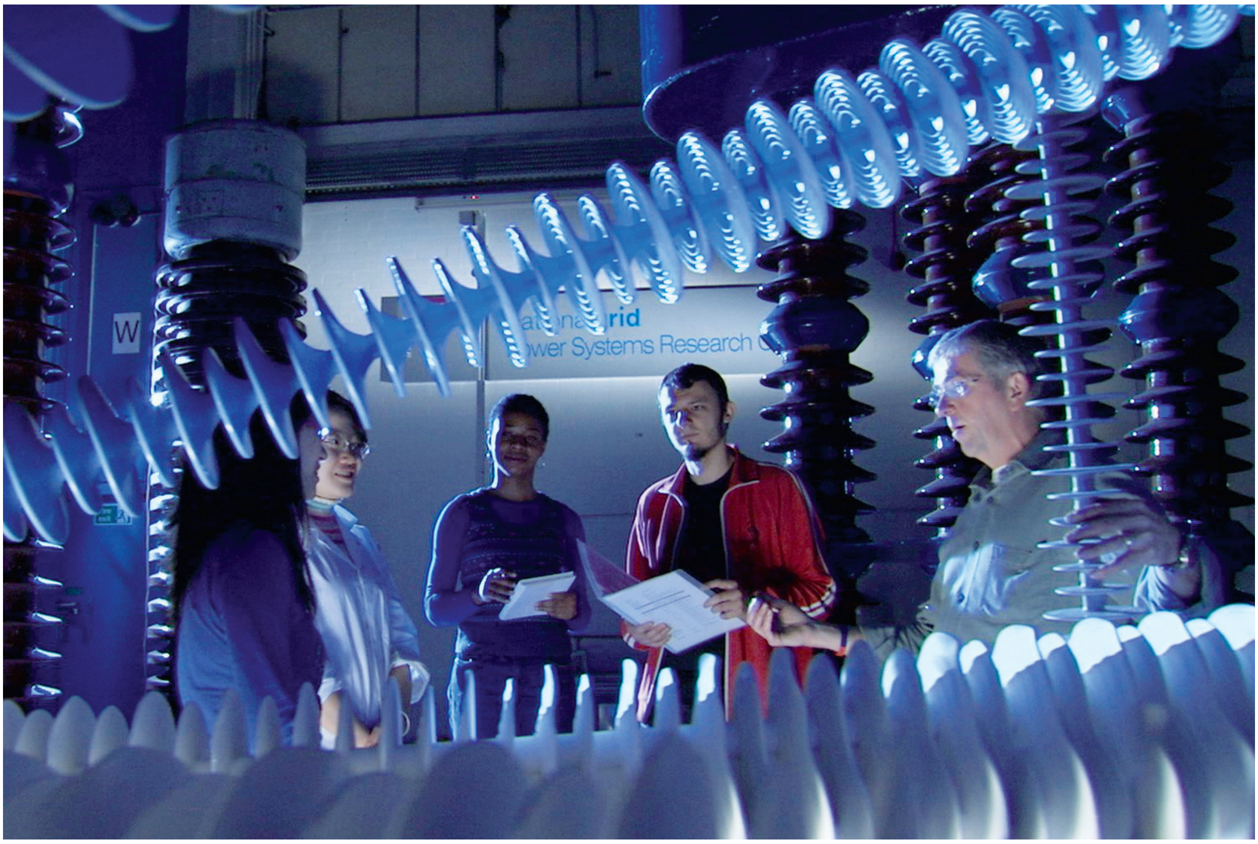
For further information on our financial performance, visit our dedicated website at **http://investors.nationalgrid.com/ Legal disclaimer**

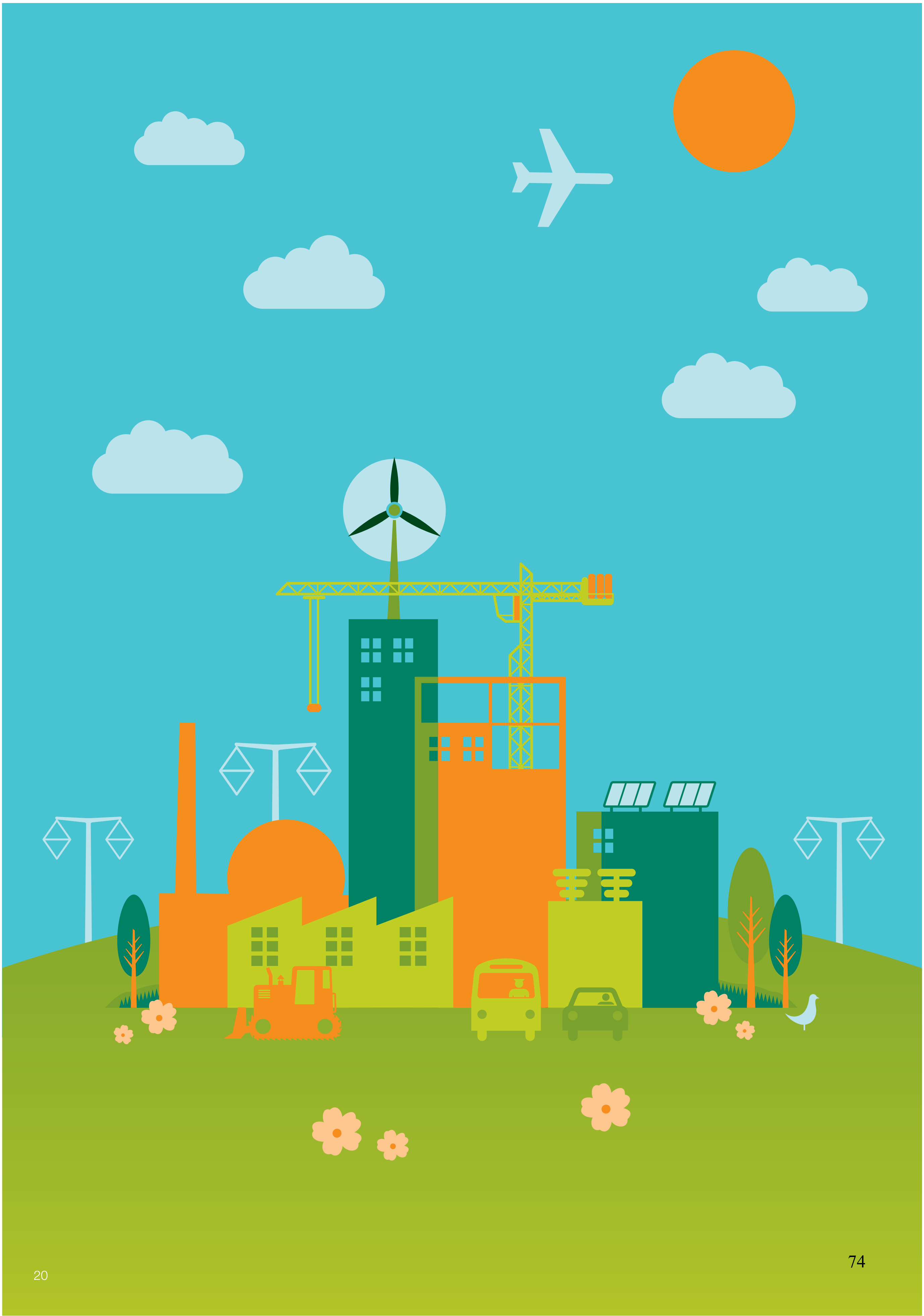
Legal disclaimer

This document contains certain statements that are neither reported financial results nor other historical information. These statements are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

These statements include information with respect to National Grid plc's financial condition, its results of operations and businesses, strategy, plans and objectives. Words such as 'anticipates', 'expects', 'should', 'intends', 'plans', 'believes', 'outlook', 'seeks', 'estimates', 'targets', 'may', 'will', 'continue', 'project' and similar expressions, as well as statements in the future tense, identify forward-looking statements.

Furthermore, this document, which is provided for information only, does not constitute summary financial statements and does not contain sufficient information to allow for as full an understanding of the results and state of affairs of National Grid plc and its subsidiaries, including the principal risks and uncertainties facing National Grid plc, as would be provided by the full Annual Report and Accounts, including in particular the Strategic Report section and the 'Risk factors' on pages 173 to 176 of National Grid plc's latest Annual Report and Accounts. Copies of the most recent Annual Report and Accounts are available online at **www2.nationalgrid.com** or from Capita Registrars. Except as may be required by law or regulation, National Grid plc undertakes no obligation to update any of its forward-looking statements, which speak only as of the date of this document. The content of any website references herein do not form part of this document.





explain
market research

National Grid Transmission
Stakeholder General Questionnaire
Draft Sample

Questionnaire

Introductory

Hello, can I speak to <respondent name> please?

My name is <agent name> and I am calling from Explain on behalf of National Grid Electricity/Gas Transmission. They contacted you recently by email regarding their Stakeholder Research Process and how we'd like to speak to you in relation to the interactions you have with them. It'll take less than 5 minutes.

If customer hesitates or wants further explanation on the purpose of the survey please say:

National Grid want to measure how well they are doing and your input is an important part of this process. The results are used by National Grid to highlight the areas where they need to improve or where they can build on their current performance.

National Grid will also donate £10 to their chosen charity for each completed interview.

Q1 Would you be able to spare some time to talk about the service you received from them?

- Yes – continue with interview
- No – too busy/not a convenient time - **is there a more convenient time I could call back?** [Interviewer to make appointment]
- No - do not want to participate – **Would you be happy for me to send you an online version of the survey?** [If yes, please capture email address]

Thank you, please note this call is being recorded for quality, training and research purposes, and will be conducted in line with Market Research Society guidelines.

I'm going to start by just asking you a few general questions around your service experience with National Grid Electricity/Gas Transmission, so firstly…

Warm Up Questions

Q2 How long have you been working with National Grid Electricity/Gas Transmission in your current role?

- 0-2 years
- More than 2 years but less than 5
- More than 5 years

Q3 Approximately how often have you had contact with National Grid Electricity/Gas Transmission in the past year?

- Once
- Twice
- Once every 2-3 months
- Every month
- Every week

Ovreall Satisfaction Question

Q4 Overall on a scale of 1 to 10, where 1 is very dissatisfied and 10 is very satisfied, taking all aspects of the service you have received into account, how satisfied are you with National Grid Electricity/Gas Transmission?

- 1
- 2
- 3
- 4
- 5
- 6
- 7
- 8
- 9
- 10
- Unsure (DO NOT PROMPT)

Q5 Again, taking all aspects of the service provided by National Grid Electricity/Gas Transmission into account, what could they have done better?

Open question

Fixed Questions

Q6 Using the scale of 1 to 10, how satisfied are you with the communication you have with National Grid Electricity/Gas Transmission?

- 1 – very dissatisfied

- 2
- 3
- 4
- 5
- 6
- 7
- 8
- 9
- 10 – very satisfied
- Unsure (DO NOT PROMPT)

Q7 *If Q6= 1-5;* "What could National Grid do to improve in this area?"

***If Q6= 8-10;* "What does National Grid do well which has led you to give a high score?"**

***If Q6= Unsure;* "If respondent unsure please note any comments made as to why"**

Open question – Interviewers to probe for details

Q8 What do you think works well regarding the interactions you have with National Grid?

Open question – probe around comments e.g why do you say that…

Q9 And what do you think could be improved?

Open question

Overall capture question

Q10 Is there anything else that we haven't covered in this survey that you would like to feed back to National Grid?

Open question – coded based upon pre-agreed list

Q12. Finally, I am going to read out a statement and I'd like you to say whether you agree / disagree or are unsure:

"I believe that action will be taken from the feedback provided through this survey."

- **Agree**
- **Disagree**
- **Unsure**

Closing statement

Q13 National Grid would like to understand individual comments and respond to any issues you may have had, are you happy to have your name attached to your responses and to have your contact details passed on to them for this purpose?

- Yes
- No *(anonymous)*

That's all the questions I have for you today, thank you for providing your feedback, it's greatly appreciated

Close

explain
market research

National Grid Electricity Transmission

Electricity Connections questionnaire inc. NPS

Draft Sample February 2018

Questionnaire

Introductory

Hello, can I speak to <respondent name> please?

My name is <agent name> and I am calling from Explain on behalf of National Grid Electricity Transmission. They contacted you recently by email regarding their customer satisfaction research and how we'd like to speak to you in relation to *the interactions you have with them regarding the Electricity Transmission Connections Process.*

If customer hesitates or wants further explanation on the purpose of the survey please say:

National Grid want to measure how well they are doing and your input is an important part of this process. The results are used by National Grid to highlight the areas where they need to improve or where they can build on their current performance.

National Grid will also donate £10 to their chosen charity for each completed interview.

Q1 Would you be able to spare some time to talk about the service you received from them? (approximately 5 minutes)

- Yes – continue with interview
- No – too busy/not a convenient time - **is there a more convenient time I could call back?** [Interviewer to make appointment]
- No - do not want to participate – **Would you be happy for me to send you an online version of the survey?** [If yes, please capture email address]

Thank you, please note this call is being recorded for quality, training and research purposes, and will be conducted in line with Market Research Society guidelines.

Warm Up Questions

Q2 How long have you been working with National Grid Electricity Transmission in your current role?

- 0-2 years
- More than 2 years but less than 5
- More than 5 years

Q3 Approximately how often have you had contact with National Grid Electricity Transmission in the past year?

- Once
- Twice
- Once every 2-3 months
- Every month
- Every week

Overall Satisfaction Question

Q4 Overall on a scale of 1 to 10, where 1 is very dissatisfied and 10 is very satisfied, taking all aspects of the service you have received into account, how satisfied are you with National Grid Electricity Transmission?

- 1
- 2
- 3
- 4
- 5
- 6
- 7
- 8
- 9
- 10
- Unsure (DO NOT PROMPT)

Q5 Again, taking all aspects of the service provided by National Grid Electricity Transmission into account, what could they have done better?

Open question – coded based upon pre-agreed list *IF NECESSARY, PROMPT "Which area(s) does that apply to?"*

Service Related Questions

The following questions I am about to ask are more specific questions about the electricity connections process.

Q6 On the scale of 1-10, how satisfied are you with the communication from the National Grid Connections Team during the connections processs?

- 1 – very dissatisfied
- 2
- 3
- 4
- 5
- 6
- 7
- 8
- 9
- 10 – very satisfied
- Unsure (DO NOT PROMPT)

Q7 *If Q6 = 1-7;* "What could National Grid do to improve in this area?"

***If Q6 = 8-10;* "What does National Grid do well which has led you to give a high score?"**

***If Q6 = Unsure;* "If respondent unsure please note any comments made as to why"**

Open question – Interviewers to probe on engagement, calls, meetings etc

Q8 And using the same scale, how would you rate your overall satisfaction with the Connections team?

- 1 – very dissatisfied
- 2
- 3
- 4
- 5
- 6
- 7
- 8
- 9
- 10 – very satisfied
- Unsure (DO NOT PROMPT)

Q9 *If Q8 = 1-7;* "What could National Grid do to improve in this area?"

***If Q8= 8-10;* "What does National Grid do well which has led you to give a high score?"**

***If Q8 = Unsure;* "If respondent unsure please note any comments made as to why"**

Open question – Interviewers to probe for further details

Q10 What do you think works well with the connections process?

Open question – coded based upon pre-agreed list

Q11 And what do you think could be improved?

Open question – coded based upon pre-agreed list

Q12. Finally, I am going to read out a statement and I'd like you to say whether you agree / disagree or are unsure:

"I believe that action will be taken from the feedback provided through this statement."

- **Agree**
- **Disagree**
- **Unsure**

Closing statement

Q13 National Grid would like to understand individual comments and respond to any issues you may have had, are you happy to have your name attached to your responses and to have your contact details passed on to them for this purpose?

- Yes
- No *(anonymous)*

That's all the questions I have for you today, thank you for providing your feedback, it's greatly appreciated

Close

Promoting choice and value
for all gas and electricity customers

Strategy decision for the RIIO-ED1 electricity distribution price control

Outputs, incentives and innovation

Supplementary annex to RIIO-ED1 overview paper

Reference: 26a/13

Publication date: 04 March 2013

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Overview:

The next electricity distribution price control, RIIO-ED1, will be the first to reflect the new RIIO 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 for delivery.

In September 2012 we consulted on the key elements of the regulatory framework ("strategy") that the 14 electricity distribution companies (DNOs) will need to understand in order to develop their business plans. We are now setting out our decision on this strategy. This supplementary annex to the main decision document sets out our decisions on the outputs that DNOs will need to deliver over the price control period, the associated incentive mechanisms and our decisions on innovation. This document is aimed at those who want an in-depth understanding of our decisions. Stakeholders wanting a more accessible overview should refer to the main overview decision document.

Associated documents

Strategy decision for RIIO-ED1 - Overview
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecOverview.pdf

Links to supplementary annexes

- Strategy decision for RIIO-ED1 - Outputs, incentives and innovation
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecOutputsIncentives.pdf
- Strategy decision for RIIO-ED1 - Business plans and proportionate treatment
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecBusinessPlans.pdf
- Strategy decision for RIIO-ED1 - Uncertainty mechanisms
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecUncertaintyMechanisms.pdf
- Strategy decision for RIIO-ED1 - Financial issues
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecFinancialIssues.pdf
- Strategy decision for RIIO-ED1 - Tools for cost assessment
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecCostAssessment.pdf
- Strategy decision for RIIO-ED1 – Reliability and safety
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1DecReliabilitySafety.pdf
- RIIO-ED1 Glossary of terms
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1SConGlossary.pdf

Links to other associated documents

- Strategy consultation for RIIO-ED1 - Overview
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1SConOverview.pdf
- Open letter consultation on the way forward for RIIO-ED1
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1LaunchOpenLetter.pdf
- Handbook for implementing the RIIO model
http://www.ofgem.gov.uk/Networks/rpix20/ConsultDocs/Documents1/RIIO%20handbook.pdf
- Electricity Distribution Price Control Review 5 (DPCR5) Final Proposals
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/FP_1_Core%20document%20SS%20FINAL.pdf

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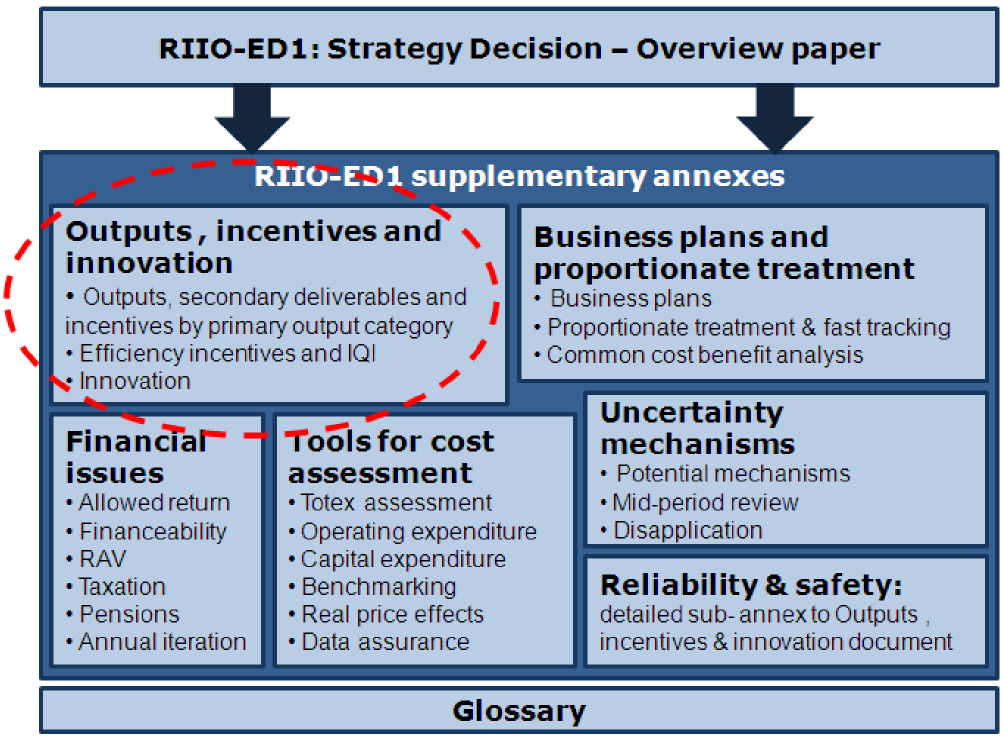
1. Introduction

1.1. This supplementary annex to the 'Strategy decision for the RIIO-ED1 electricity distribution price control' sets out our decisions on the outputs that DNOs will need to deliver over the RIIO-ED1 period, and the associated incentive mechanisms. It also sets out our approaches to setting the efficiency incentives and the operation of the information quality incentive (IQI), and describes the package of measures that will stimulate innovation.

1.2. This document is aimed at those who want an in-depth understanding of our proposals. Stakeholders wanting a more accessible overview should refer to the 'Strategy decision - Overview'. Figure 1.1 below provides a map of the RIIO-ED1 documents published as part of this decision.

Figure 1.1: RIIO-ED1 Supplementary annex document map



Links to these documents can be found in the 'Associated documents' section of this document

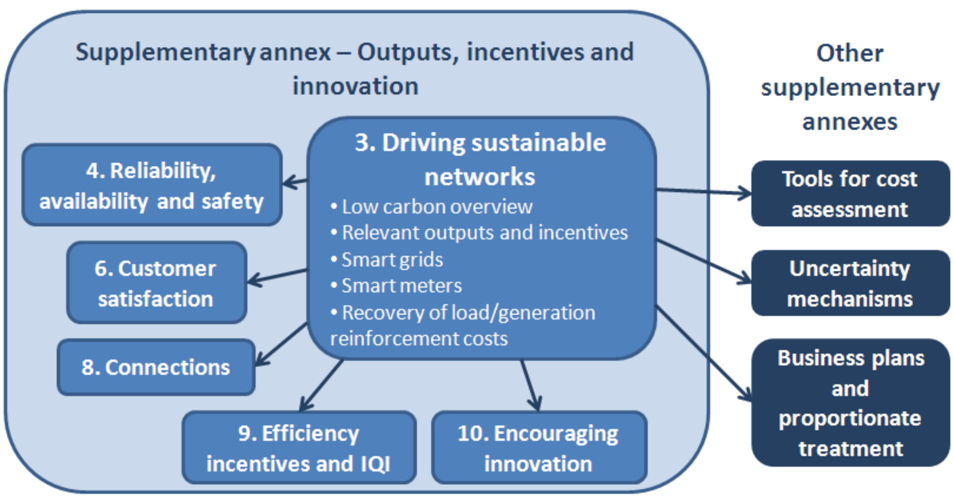
Facilitating the low carbon future

1.3. We think that the DNOs' key challenge for RIIO-ED1 is ensuring that they will be able to connect the new low carbon loads required to achieve the national emissions targets. They will need to enable these loads and generation to connect in an appropriate timeframe, at appropriate cost, without causing network problems and without incurring excessive costs.

1.4. We believe this behaviour will be driven by a coherent and balanced package of outputs and incentives, alongside a combination of ex ante assessment and appropriate uncertainty mechanisms. Since these mechanisms are described in different chapters of this decision, we have included a chapter at the start of this document (Chapter 3 - Driving sustainable networks) setting out how our individual mechanisms will incentivise the DNOs to ensure that their networks have the necessary flexibility and capacity to connect these new loads. A diagram of how the Driving sustainable networks chapter links with other chapters and documents is shown in Figure 1.2 below.

1.5. Smart grids solutions will be an important way of delivering the outputs at reasonable cost. However, they are a means of delivering an output, rather than an output themselves. We consider that DNOs' progress on enabling the transition to a smarter, low carbon network will be measured and incentivised through the package of outputs we have proposed. We have also set out our thinking on this in Chapter 3.

Figure 1.2: Map of the Driving sustainable networks chapter and linked chapters and documents



Summary of proposed outputs and incentives

1.6. Table 1.1 below summarises the key elements of the proposed RIIO-ED1 outputs.

Table 1.1: Summary of RIIO-ED1 outputs framework

Primary output category	RIIO-ED1 outputs and incentives
Safety	• Compliance with the legislative and regulatory framework regulated by the Health and Safety Executive (HSE).
Environmental impact	• Replace DPCR5 losses incentive with: an obligation to reduce losses, ex ante funding for loss reduction activities and a discretionary reward for efficient and innovative loss reduction initiatives. • Maintain reputational incentive for business carbon footprint (BCF). • Maintain allowance for undergrounding overhead lines in areas of outstanding natural beauty and national parks. • Introduce a reputational reporting requirement on broad environmental impact.
Customer satisfaction	• Strengthen the Broad Measure of Customer Satisfaction (BMCS) introduced in DPCR5.

Social obligations	• Putting in place incentives to ensure DNOs play a full role in addressing consumer vulnerability, through:
	  • improving the information they hold on customers connected to their wires and identifying how they can improve the assistance they provide
	  • engaging with a wide range of other agencies to ensure customers get access to support that is available
	  • identifying opportunities to enable energy solutions for vulnerable households that might also reduce demands on the distribution network
	• The stakeholder engagement incentive rewards DNOs that demonstrate the delivery of benefits result from the above.

Connections	• For smaller connection types – increase in the incentive value associated with the customer satisfaction survey and introduce a new incentive relating to the average time taken to connect customers. • For larger connection types – introduce a new Incentive on Connections Engagement (ICE), requiring DNOs to engage with and understand the requirements of different customers. • Maintain underlying framework of licence conditions and guaranteed standards of performance to safeguard minimum levels of performance for all customers.
Reliability and availability	• Continue existing interruption incentive scheme (IIS) with small improvements. Improve the consistency of the asset health and loading indices secondary deliverables. • Reduced payment threshold under the guaranteed standards of reliability and uniform coverage. • Maintain the DPCR5 mechanism for worst served customers. • Introduce secondary deliverables on network resilience.

Structure of document

1.7. The remainder of this document sets out our output measures and incentive mechanisms for the six primary output categories, alongside our approach to the efficiency incentive and the Information Quality Incentive (IQI), and the package of mechanisms to stimulate innovation. The document leads with an overview of the outputs and incentives and how they are designed under RIIO. This is followed by an overarching chapter setting out how we think our RIIO-ED1 proposals will encourage DNOs to anticipate the low carbon future.

1.8. The chapters are set out as follows:

- Chapter 2: Overview of outputs and incentives
- Chapter 3: Driving sustainable networks
- Chapter 4: Reliability and safety
- Chapter 5: Environmental impacts
- Chapter 6: Customer satisfaction
- Chapter 7: Social obligations
- Chapter 8: Connections
- Chapter 9: Efficiency incentives and IQI
- Chapter 10: Encouraging innovation.

2. Overview of outputs and incentives

Chapter Summary

This chapter summarises our overall approach to identifying the outputs that DNOs will need to deliver during RIIO-ED1, as well as our approach to setting the associated incentive mechanisms. We also discuss our approach to regulatory reporting requirements which will support the outputs-based framework.

Outputs-led framework

2.1. Outputs are at the heart of the RIIO regulatory framework. Base revenues and incentives are linked to the delivery of these outputs. Their delivery should also form the core of the companies' business plans.

2.2. We expect DNOs to deliver outputs in the six RIIO primary output categories: safe network services, environmental impact, customer satisfaction, social obligations, connections, and reliability and availability.

Stakeholder engagement

2.3. We have continued the working groups[1] to assist us to develop further the outputs and incentive mechanisms in light of the responses to our September strategy consultation. Our decisions reflect the working group discussions and consultation responses as well as views expressed at other stakeholder forums. Our decisions have also been informed by discussions with the Consumer Challenge Group, a small group of consumer experts, which acts as a 'critical friend' to Ofgem in ensuring that the views of consumers are considered fully in the review.

Output measures

2.4. The outputs framework comprises both primary outputs and secondary deliverables. Primary outputs concern aspects of the network services provided directly to customers. Secondary deliverables are indicators of performance which may be used in support of the required primary outputs.

2.5. The primary outputs are designed to be: controllable by the DNOs, measurable, auditable and comparable. Where components of the DPCR5

[1] Full details of all RIIO-ED1 workings groups, including minutes and slide packs can be found on our website: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/working-groups/Pages/index.aspx

framework are working well and satisfy the RIIO principles (such as the interruptions incentive and DNOs' reporting of their carbon footprint), we are maintaining them as part of RIIO-ED1.

2.6. If a DNO is only focused on delivery of primary outputs in the forthcoming price control period, there is a risk that it will miss opportunities to take action that could improve its delivery of primary outputs in future periods. We therefore expect DNOs to include in their business plans the costs required to deliver primary outputs beyond RIIO-ED1. To ensure that consumers do not pay unnecessarily high prices, DNOs will be expected to set out the rationale for expenditure in the context of a long-term delivery strategy.

Setting baselines

2.7. For many of the outputs we plan to set the level (or baseline) to be delivered, taking into account stakeholder views. However for some outputs and secondary deliverables (such as the asset health and loading indices), DNOs will need to set out their proposed level of delivery in their business plans. This level should be justified in terms of the costs and benefits to network users and should be informed by their stakeholder engagement.

Incentive mechanisms

2.8. For each output category, we have considered a range of incentive mechanisms to encourage DNOs to deliver the primary outputs and secondary deliverables at value for money to current and future consumers. These incentives include financial rewards/penalties and reputational incentives. Our objective is to create a streamlined and balanced package of outputs and incentives which are clear to DNOs and do not create any perverse incentives. Our intention is that the total incentive package ensures that those DNOs that deliver for consumers earn an attractive rate of return, whereas those that demonstrably do not deliver will earn low returns.

2.9. The structure of the incentive mechanism, for example whether is it symmetric/asymmetric, and the basis for setting the reward/penalty depends on the output measure. If a DNO earns a reward, the amount of revenue it is allowed to raise from customers increases, thereby increasing its return. Conversely a penalty means that the amount of revenue it raises decreases and reduces its return.

2.10. We have not included financial incentive mechanisms for all output measures. For example, we have not proposed any financial incentives for the set of safety related outputs. For these outputs, DNOs need to comply with legal obligations, and are subject to Health and Safety Executive (HSE) enforcement action in the event of non-compliance.

2.11. We have designed the incentives taking into account the status of competition. This is particularly relevant for connections, where independent providers can provide connections services as well as DNOs. Where effective competition exists to protect the customers' interests we have been mindful not to provide potential incentive benefits to DNOs that are not available to these independent providers.

2.12. The DNOs are incentivised to deliver the outputs at efficient cost. Our assessment of the business plans encourages the companies to propose solutions that offer value for money. Once the settlement has been determined, the efficiency incentive provides an ongoing incentive for them to seek out lower cost solutions and manage the cost of output delivery. (The efficiency incentive is described in more detail in Chapter 9). We expect that in many cases innovation, including the implementation of smart grids techniques (such as demand side response), should enable DNOs to deliver outputs at long-term lower costs than conventional solutions.

Caps and collars

2.13. For some outputs and incentives we have set upper and/or lower limits on the revenue adjustment. These limits are dependent on:

- the extent to which we think it is appropriate for consumers to pay for more or less of an output relative to what was assumed when the price control was set
- the extent to which there is useful information on customers' valuation of the outputs
- the robustness of the information that is available both to set targets and measure performance against them.

2.14. Where we use caps and collars we have designed them to limit the risk of creating perverse incentives and aim to make them as simple as possible.

2.15. We will set caps and collars as fixed £m, derived from a consistent potential DNO shareholder return from the incentive (the return on regulatory equity, RORE). We will set the £m limits based on the same number of basis points for each DNO. In our decisions for customer satisfaction and connections we have also stated the equivalent percentage base revenue[2] for comparison with our September strategy consultation and DPCR5.

2.16. In our September strategy consultation we noted that we have historically used two different approaches to set caps and collars; basis points and

[2] Historically we have used the term 'allowed revenues'. However it is more correct to use 'base revenues', since 'allowed revenues' includes incentives – effectively make the calculation of caps and collars circular.

percentage of allowed revenues. All but one respondent favoured basis points.

2.17. We note that we will not be able to set the value of caps and collars until the Draft/Final Determination for any DNO, since the value will be dependent on the base revenues allowed for the company.

Recovery of incentive rewards or penalties

2.18. Responses to our September strategy consultation reiterated the concerns of some stakeholders about the volatility of network charges. In October 2012 we published our decision on options to improve the predictability, and reduce the volatility, of charges arising from the price control settlement, including the impact of incentive rewards and penalties.[3] Our decision was to increase the lag on incentive rewards/penalties that network companies recover through allowed revenues, and increase the lag on adjustments to allowed revenues from some types of uncertainty mechanisms. We have adopted these decisions for RIIO-ED1. Incentives will be funded with a two-year lag so that performance in one year will be reported in the next, and the reward or penalty will feed into allowed revenues (and therefore charges) the year after. Volume drivers and pass-through items will be funded in the same way.

2.19. Respondents also expressed concern over the visibility of a potential step change in charges between the end of DPCR5 and the start of RIIO-ED1. We are not making any changes to the RIIO-ED1 process at this time, but are establishing a separate work stream to look at this issue.

Monitoring output delivery and reporting

2.20. We will need to be able to monitor and evaluate the DNOs' performance against the proposed set of outputs. In the current price control our main reporting mechanism is the Regulatory Instructions and Guidance (RIGs), which provide a common framework for DNOs to report relevant performance data and cost information.

2.21. For RIIO-ED1, we will need to revise and expand the current RIGs to enable us to monitor DNOs' performance against the proposed output measures. We propose to start work early on the development of RIGs for RIIO-ED1 and to issue draft revised RIGs in advance of our Final Determination in November 2014. We will work with the industry in developing common reporting templates which will form part of the RIGs.

2.22. Respondents to our September strategy consultation did not think there were any serious potential difficulties in ensuring the submission of accurate and

[3] Decision on measures to mitigate network charging volatility arising from the price control settlement, 17/10/2012, available at http://www.ofgem.gov.uk/Networks/Policy/Documents1/CV_Decision.pdf

comparable data across our proposed outputs. Some DNOs noted specific areas which may cause problems (which have been considered in the relevant sections of this document). One respondent flagged that steps to improve comparability and harmonisation should not stifle innovation. Most respondents did not think the reporting requirements were likely to lead to disproportionate regulatory costs.

2.23. The RIIO model sets out a balanced scorecard approach to assessing company performance. The purpose of the scorecard is to provide a clear and simple way to convey information about network company performance and to facilitate a meaningful comparison of performance over time. We are using this approach in the existing electricity distribution annual report[4] which we will update in the first year of RIIO-ED1 to reflect the RIIO-ED1 outputs.

2.24. As part of their reporting, DNOs will need to provide data assurance. Our requirements for RIIO-ED1 encompass two broad principles. First, that the onus is placed firmly on the DNOs to ensure the integrity of data submitted to Ofgem. Second, that data assurance is risk-based and the data assurance activity adopted for each data submission is proportionate to that risk.

2.25. DNOs will have to comply with a new data assurance licence condition and the Data Assurance Guidance (DAG).[5] The DAG will provide guidance on best practice for conducting and reporting data assurance activities to ensure complete, accurate and timely data is submitted to Ofgem.

2.26. While the reporting requirements (ie what and when data should be reported to Ofgem) will be set out in the Regulatory Instructions and Guidance (RIGs), the DAG will set out the processes DNOs should follow in order to assure the accuracy, completeness and timely submission of that data.

Changes to outputs

2.27. Recognising the scope for significant changes in outputs during an eight-year price control period, the RIIO framework sets out a provision for a mid-period review of output requirements. In setting a mid-period review there is a risk that it could undermine the purpose of setting a longer price control period. Consequently, we propose to restrict the scope for the mid-period review to changes to outputs that can be justified by clear changes in government policy and the introduction of new outputs that are needed to meet the needs of consumers and other network users. This is discussed in more detail in the 'Supplementary annex – Uncertainty mechanisms'.

[4] The most recent report, for 2010-11, can be found at: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Electricity_Distribution_Annual_Report_for_2010_11.pdf
[5] We have been working with DNOs in a DPCR5 trial to develop the Data Assurance Guidance (DAG) document.

3. Driving sustainable networks

Chapter Summary

This chapter sets out how the separate elements of our decision on outputs and incentives work together to encourage and facilitate DNOs to fulfil their role in a low carbon economy. It also sets out our decision on how to address potential barriers to DNOs fulfilling this role. It signposts where further details on each aspect of the framework can be found within the suite of decision documents.

Introduction

3.1. We identified in the September strategy consultation that a key challenge for RIIO-ED1 would be how DNOs accommodate and facilitate the increase in low carbon technologies. These include heat pumps, electric vehicles (EVs) and distribution connected generation (DG), which are being driven by the government's climate change targets. There is considerable uncertainty around the volume and location of take up of these technologies.

3.2. This chapter sets out how the various outputs and incentives for RIIO-ED1 will encourage DNOs to provide a high-level of service for connections, while maintaining a reliable network and continuing to deliver value for money for existing and future customers. It outlines the role that smart grids can play in helping DNOs meet this challenge. In addition, it clarifies who should pay for reinforcement of the network required to accommodate load and generation growth associated with the connection of low carbon technologies at existing domestic premises.

3.3. Alongside the framework set out below there are a number of key elements which we consider have a crucial role in helping DNOs facilitate the transition to a low carbon economy. In our September strategy consultation we set out our proposals for these elements as part of this chapter. However, we think that decisions for the following elements sit more logically elsewhere in the suite of decision documents:

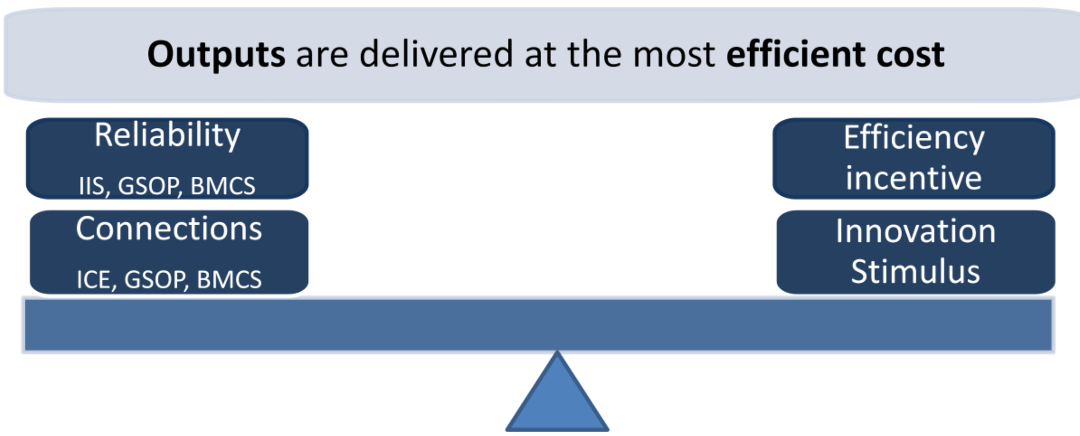
- the level of detail required on scenarios for business plan submissions (Supplementary annex – Business plans and proportionate treatment, Chapter 4)
- uncertainty mechanisms for the load related expenditure reopener (Supplementary annex – Uncertainty mechanisms, Chapter 3)
- treatment of smart meter roll-out costs (Supplementary annex – Uncertainty mechanisms, Chapter 3).

Specific low carbon technologies incentive

Our decision

3.4. We have concluded that a specific output or incentive for the connection of low carbon technologies is not required for RIIO-ED1. We consider that the package of outputs and incentives which are set out in the other chapters of this document are sufficient to drive the behaviours required to facilitate the transition to a low carbon economy. Figure 3.1 provides a high-level summary of the key aspects of the framework of output and incentives for RIIO-ED1.

Figure 3.1: high-level output framework[6]



3.5. The detail of the reliability, customer satisfaction and connection outputs and incentives depicted in Figure 3.1 are set out in Chapters 4, 6 and 8 of this document respectively. At a high level, they interact with the efficiency incentive (Chapter 9) and innovation stimulus (Chapter 10) to drive the behaviour required from DNOs to respond to and facilitate the connection of low carbon technologies and distributed generation (DG) within the RIIO-ED1 period.

Delivering outputs

3.6. Unless the network has adequate spare capacity, the connection of heat pumps and/or EVs could lead to supply interruptions where their additional demand overloads the network. Under the interruptions incentive scheme (IIS), DNOs will face financial penalties for the number and duration of interruptions. The prospect of these penalties will drive DNOs to be proactive

[6] The acronyms used in this diagram are: IIS – Interruption Incentive Scheme; GSOP – Guaranteed Standards of Performance; BMCS – Broad Measure of Customer Satisfaction; ICE – Incentive for Connections Engagement

in ensuring that the low voltage (LV) network is resilient to anticipated increases in demand and generation.

3.7. For large connections, including DG, a new incentive on connections engagement (ICE) will drive improved engagement and higher levels of service. Under ICE, DNOs will need to engage with stakeholders and use their feedback to agree a work plan and relevant targets to measure performance. We will assess performance against these targets and companies will face penalties if they fail to deliver. This will drive DNOs to meet DG customers' expectations of levels of service.

3.8. Finally, the guaranteed standards of performance (GSOP) set out minimum levels of service which DNOs must meet in terms of reliability and time to connect new demand and generation. DNOs will provide payments to customers if they fall below these standards.

At efficient cost

3.9. DNOs will have an ex ante allowance to deliver the outputs set out in this document. In Chapter 9 we set out an efficiency incentive whereby companies can retain up to 70 per cent of any under spend whilst funding 70 per cent of over spend against this allowance, with customers retaining or funding the remaining 30 per cent. This provides a strong incentive on companies to deliver outputs at efficient cost. It will also drive DNOs to consider how smart grid solutions, such as demand side response (DSR) can deliver outputs at lower cost than conventional techniques.

3.10. The innovation stimulus will supplement the efficiency incentive by providing learning on the costs and benefits of innovative techniques, including smart grids. This learning will help inform DNOs where they can start to deploy these techniques as business as usual and drive down costs over time.

Summary of consultation proposals and respondents' views

3.11. The decision not to include a specific incentive for the connection of low carbon technology is in line with our proposals in the September strategy consultation. There was widespread support for this proposal amongst respondents. However, UKPN stated that whilst the proposed framework would protect against poor performance in connecting low carbon technologies, they felt that DNOs should be incentivised to look for more innovative solutions. RenewableUK shared these concerns as did BEAMA who commented that there may be little incentive on DNOs to invest in smart solutions to help connect low carbon technologies.

3.12. The remaining DNOs were all supportive, with one commenting that connection of low carbon technologies was outside of the control of network companies and so it would be inappropriate to incentivise them on it. Another commented that our proposals already contained a range of incentives and requirements on DNOs to facilitate the transition to a low carbon economy. Suppliers were also supportive, whilst emphasising the need for DNOs to enable new types of low carbon connection. Consumer Focus stated that whilst the proposed framework seemed sensible, it would be important to see if the value of the incentives were appropriately balanced.

Reasons for our decision

3.13. We agree with the majority of respondents that the range of incentives we have presented are sufficient to drive the behaviour from DNOs required to help facilitate a low carbon economy. For an incentive to be effective, DNOs must be able to control their performance in relation to it. We agree that DNOs are not in control of where low carbon technologies and DG request to connect and therefore, it would be inappropriate to place a specific incentive on connecting them.

3.14. We consider it more appropriate to incentivise DNOs to respond to the volume of low carbon technologies and DG connecting to their networks. This is within their control. We consider that the package of outputs and incentives does not simply drive minimal levels of performance but encourages DNOs to strive for excellence. For example, under the efficiency incentive, DNOs will be encouraged to deploy new innovative solutions (potentially already trialled through the LCN Fund and Innovation Stimulus) where they can reduce costs.

Smart Grids

3.15. Through the Smart Grid Forum[7], we have undertaken extensive work in conjunction with DECC, DNOs and other industry parties to help understand the role which smart grids can play in RIIO-ED1. Through this work, low carbon scenarios produced by DECC have been combined with the smart grid solutions evaluation framework, initiated by Ofgem and taken forward by the DNOs. This has been captured in the work stream 3 model.[8]

3.16. This has indicated that the deployment of smart grid solutions has potential benefits over conventional reinforcement under some scenarios. The take up of low carbon technologies is predicted to increase significantly during RIIO-ED2 and RIIO-ED3, the modelling indicates that, over time, a more integrated "top down" smart grid is likely to have benefits over traditional methods. The RIIO-ED1 period represents an opportunity to start to deploy smart grid solutions and get prepared for the more radical network changes that may be required in the future.

[7] This was jointly established by DECC & Ofgem in 2011 to provide leadership on smart grid issues in GB.
[8] Also called the 'Transform' model elsewhere in this decision. More information can be found at http://www.ofgem.gov.uk/Networks/SGF/Publications/Documents1/Smart%20Grid%20Forum%20Workstream%203%20Report%20071011%20MASTER.pdf

Our decision

3.17. We have decided that DNOs must demonstrate how they have considered using smart grid solutions as part of their core business if they wish to be fast-tracked. This is in response to stakeholder concerns that despite financial incentives on DNOs to start deploying smart grid solutions in RIIO-ED1, companies may be slow to do so.

3.18. We have also decided that DNOs can pass through any fixed costs of smart metering data up until the smart meter roll out is complete at the end of 2019. While some of the benefits will start being realised during the roll out period, we expect that DNOs will be able to realise the full benefits from this data once the roll out is complete. Consequently, we expect that DNOs' use of smart metering data from 2019 onwards will deliver at least an amount of benefits which offsets all of the fixed costs of obtaining that data.

3.19. This means that beyond 2019, we will treat the fixed costs as any other cost which the DNO will be expected to fund from the benefits realised. For the avoidance of doubt, we are not providing ex ante funding for any of the variable costs of smart metering data – since the DNOs should only incur these where they can realise sufficient benefits to fund them.

3.20. We expect the DNOs to set out their strategies for maximising the value that they will leverage from the smart meter roll-out in their business plans. Based on these strategies we expect the DNOs to make full use of the smart metering capabilities and services to maximize the benefits of the smart metering programme on behalf of consumers.

Assessing DNO progress in adopting smart grid solutions

3.21. The consideration of smart grid solutions will need to be at the heart of the DNO's business plan if they wish to be eligible for fast tracking. DNOs who fail to consider fully the use of such solutions in their core business risk falling behind our assessment of efficient cost. We expect a well-justified business plan to:

- clearly demonstrate how they have considered alternative solutions in their cost benefit analysis in order to justify expenditure
- outline how learning from LCN Fund projects has been embedded into their core business
- use the work stream 3 model, alongside similar tools, to clearly articulate a strategy for the deployment of smart grid solutions in RIIO-ED1
- use the work stream 3 model, alongside similar tools, to demonstrate how their investment plan can 'flex' to provide value for money if a different low carbon scenario emerges within the price control period
- outline a strategy for how they will use the RIIO-ED1 period to prepare for future challenges in RIIO-ED2 and ED3, including an assessment of the option value and the full life benefits of proposed smart grid investments

- set out a clear strategy for the intelligent use of data in their business alongside analysis demonstrating the cost of this data and supporting systems is outweighed by the benefits to customers
- set out in the innovation strategy how they will build on current learning and smart grid deployment to test new techniques, including arrangements with customers and other parties in the value chain.

3.22. As set out in Chapter 10, we plan to review the level of funding available to DNOs under the Network Innovation Competition (NIC) in 2016. If DNOs do not demonstrate clear evidence of how emerging learning will be deployed in business as usual, then there may be a strong case for removing NIC funding for DNOs post 2016. In order to gather evidence, we are minded to require DNOs to include smart grid solutions deployed as part of the reputational environmental reporting requirement. This is discussed further in Chapter 5.

3.23. In the future, we will also consider whether an additional criterion for the initial screening process is required for the NIC under which DNOs will need to demonstrate how they are deploying smart grid solutions within their business. If DNOs are unable to do this, they may not be eligible to compete for funding.

Smart grid developments during RIIO-ED1

3.24. The toolkit of smart grid solutions is likely to expand over RIIO-ED1 as further learning emerges from the LCN Fund and innovation stimulus trials. In addition, the cost of these solutions could fall over time, improving their business case during the price control period. We are confident that the framework we have set out in this chapter is sufficiently flexible to allow DNOs to make use of these developments within RIIO-ED1.

3.25. In parallel to RIIO-ED1, we will commence a project to look at the options for the development of smart grids, particularly in terms of how smart grids will engage with customers. This engagement could take a number of different forms. For example, it could enable customers to respond to price signals. Alternatively, customers could make an upfront choice about what appliances they are willing to have interrupted, how often, for how long and when. Once these preferences are set, they could be used to drive a more automated smart grid.

3.26. The roles of industry parties and the relationships between them may need to change depending on which of these options (or others) emerges. The project will outline what these roles and relationships could look like for each identified smart grid option. The driver for these should be to enable a simple proposition to be put to customers which enables them to receive full benefit for their actions. The roles and relationships will also need to consider the most efficient way to maintain the stability of the electricity system from a technical perspective, in a world where there may be numerous active devices. These roles and relationships will also consider the merits of DNOs playing a role in local demand and generation balancing and behaving more like Distribution System Operators.

3.27. The project will assess the high-level commercial arrangements required between industry parties to support the most efficient discharge of the roles and relationships required for each option. This will not only provide options for smart grid development, along with associated commercial arrangements, but it will allow an assessment of these against the regulatory regime to identify where changes may need to be made to enable different smart grid options. This will ensure that we are able to initiate any required changes and implement them in a timely manner.

3.28. Our decision on the recovery of costs outlined below, places urgency on this body of work to provide a means through which customers can reduce demand at times of network peak. We will want to ensure that this means is identified and can be implemented as soon as sufficient smart metering data and enabling technology is available.

Use of data, including smart metering data

3.29. DNOs will need to consider how they can use data to improve their operations and provide benefits for customers, both in terms of cost saving and the quality of service they can offer. Smart metering data can play a critical role in the development of smart grids and we expect DNOs to be making a strong case to DECC in terms of the data they will require. This case will need to be based on the benefits which this data can provide compared to the costs of receiving that data.

3.30. Our decision on the treatment of the fixed costs of smart metering data is in line with the sentiments, expressed in the September strategy consultation, that DNOs must offset the costs of the data with the benefits they can provide to customers. Since September, DECC has provided clarity that DNO will pay their proportion of the fixed cost from day one of the smart meter roll out.

3.31. We appreciate that DNOs will not be able to realise the full benefits of smart metering data until later in the roll out period. Once these benefits start to emerge we consider it appropriate that DNOs should use them to offset the costs of the data.

Recovery of costs due to load and generation increases from existing domestic customers

3.32. In practice DNOs currently recover the cost of network reinforcement triggered by load growth at existing domestic premises through distribution use of system (DUoS) charges. This is because they are unable to identify which individual customers are driving the costs. However, since they are allowed to charge individual customers, there is the potential for inconsistent treatment across DNOs.

Our decision

3.33. Ideally, DNOs would recover costs from those customers who impose them. However, since this is currently not practicable we have decided that until DNOs have a means to accurately identify the customers who trigger cost, they will continue to recover the costs of any reinforcement caused by load or generation growth by domestic (as defined in the electricity distribution licence) and small business (profile class 3-4) customers through DUoS charges. DUoS charges are paid by all customers as part of their overall bill to reflect the costs of transporting electricity through the distribution network.

3.34. This decision will apply to all equipment installed in existing domestic or profile class 3-4 properties, including where that equipment is part of multiple installations made by a landlord.

3.35. Given the projected take up of low carbon technologies by domestic customers over time, we consider that there needs to be a consistent policy across all DNOs. Otherwise customers may be unaware of connection charges which they are liable for and face these charges only after they have installed devices.

3.36. At present the only practical policy which can apply across the board is for DNOs to recover the costs of reinforcement from all customers through DUoS charges. Without access to granular data or installing costly monitoring equipment, the only means DNOs have for identifying domestic or small business customers who may trigger reinforcement are through the types of appliances they install. DNOs are working, through the Energy Networks Association (ENA), to receive advanced notification of when certain devices are installed. However, they will not know with confidence when these devices are used and hence whether they are triggering costs.

3.37. Socialising the cost of reinforcement to accommodate domestic growth means that customers who are not adopting high energy consumption equipment may, in effect, be paying for those who do through raised DUoS charges. This reflects current practice of funding reinforcement costs through DUoS charges where DNOs cannot identify the customers who trigger these costs. A system that targets upfront connection costs at individual domestic and small business customers may not only be impracticable, but also costly as DNOs would need to identify and approach individual customers. The impact of that approach would be likely to increase DNOs’ overall costs which are passed through to all consumers.

3.38. We recognise that socialising reinforcement costs may insulate domestic and small business customers from the financial consequences of their actions, rather than actively encouraging them to properly manage their demand.[9] However, this will be an interim measure until sufficient smart metering data is available to identify those who trigger reinforcement and incentivise them to manage their consumption in order to avoid reinforcement. A key element of our smart grid project (outlined above) will be to understand how incentives on these customers to manage demand can be introduced. This goes to the heart of what form a future smart grid should take and how it should interact with customers.

Summary of consultation proposals

3.39. In our September strategy consultation we noted that there may be merits in recovering the cost of upstream reinforcement triggered by load or generation increase from existing customers (profile class 1-4) through DUoS charges. This was proposed as an interim measure until a practical mechanism is developed to incentivise customers to manage the load they place on the network. We explained that without visibility of the timing of customers' consumption, it is difficult to identify who was driving costs and therefore who should be charged. We also commented that it is easier for DNOs to receive notification of some new appliances (typically the low carbon ones which register for subsidies) than others, such as power showers and hot tubs. We outlined that it seemed unfair only to target costs associated with some appliances and not all.

3.40. We also identified four implementation issues associated with our proposal. These were; how to retain an incentive on customers to purchase equipment which poses the least power quality issues on the network; how to treat installations by landlords across multiple domestic premises; the impact on the margins which independent distribution network operators (IDNOs) can earn; and potential for a perverse incentive on developers to underestimate capacity for new build sites.

Respondents views

3.41. There was widespread support for our proposal across DNOs, suppliers and consumer groups. DNOs commented that it is currently impractical to try and charge every domestic customer who triggers reinforcement since they would never have visibility of all new appliances. Whilst supporting our proposal, one DNO highlighted that identifying domestic customers by profile class may not deliver the intended policy intent. The DNO highlighted that customers will change from profile class one or two to profile class zero when a smart meter is installed in their home. This could mean that DNOs are obliged to charge

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[9] From this point on, we refer to demand when talking about both demand and generation.

these customers before sufficient smart metering data is available from all customers.

3.42. Respondents to the consultation, particularly DNOs, stated that DNOs should reserve the right to charge customers who cause identifiable power quality issues on the network. Suppliers commented that it was the responsibility of the DNO to ensure that devices connected to their distribution network were not likely to cause network issues. This would mean there would be no need for the DNO to levy additional charges on customers but may require the DNO to approve the connection of every piece of equipment which may cause network issues.

3.43. Responses were not in agreement over whether the policy proposal would have an impact on the IDNO gross margin. Some DNOs felt that the changes in revenue caused by our proposal would feed through the charging model in its current form to ensure IDNO's regulated revenue continues to be sufficient for them to discharge their licence obligations. However, other respondents felt that changes would need to be made to the model itself to ensure IDNOs received an equivalent margin to that which is received currently.

Reasons for our decision

3.44. As a result of consultation responses, we have refined our proposals so that they will apply to domestic customers as defined in the electricity licence. This will mean that when these customers have a smart meter installed during the smart meter roll out, they will not risk being charged for reinforcement until an alternative overall strategy is established using smart metering data.

Associated implementation issues

3.45. As part of our September strategy consultation we identified a number of associated issues with the implementation of our policy proposal.

Equipment with power quality issues

3.46. Allowing DNOs discretion over charging for certain types of equipment does not provide transparency for customers. Customers need to know the likely cost of their action before they purchase equipment, rather than being presented with a connection charge once they have installed devices. We also have concerns that a policy which leaves discretion on charging with DNOs would mean that only those customers who are easily identifiable are charged. However, we will consider allowing DNOs to charge in specific circumstances in the future, if it emerges that some clearly identifiable equipment is posing significant network issues.

3.47. We recognise that this may potentially remove an incentive on customers to purchase equipment which causes fewer power quality issues but consider that this incentive can be better provided elsewhere. For example, we support the ENA’s proposal to DECC that sub-standard heat pumps that cause significant network issues and costs should be ineligible for the renewable heat incentive.

Impact on IDNOs

3.48. We will continue to work with IDNOs and DNOs to assess the impact of our decision on IDNOs’ gross margin. However, since this gross margin is a product of the common distribution charging methodology (CDCM), this is not an issue which will impact DNOs’ business plans and therefore does not need to be resolved now.

Treatment of landlords

3.49. The ENA is currently developing a notification process for the connection of low carbon technologies. This will allow DNOs to plan their network properly and ensure that it is resilient. DNO members of our policy working group have stated that if they charge for multiple installations by a landlord but not single installations by an individual, there is a clear incentive for landlords to submit consecutive applications to try and avoid charges. This could lead to the network being developed inefficiently on the basis of misleading information.

Design standards

3.50. Our decision regarding cost recovery relates to increases in load from existing connections. It does not apply to new connections, since DNOs have full visibility and must conform to design standards for new connections. We recognised in the September strategy consultation that this could create a perverse incentive on developers to request a lower capacity than will ultimately be needed, in the knowledge that any future reinforcement will be funded through DUoS charges.

3.51. We do not consider that this issue should impact DNO business plans, particularly since we are proposing a reopener to deal with the uncertainty surrounding load related expenditure. However, we consider that this is an important issue which will require further discussion with independent connections providers (ICPs), IDNOs and DNOs. One option that should be considered further is the development of a clear and consistent methodology for design standards.

Strategic investment

3.52. Strategic investment is investment made in network assets in anticipation that customers will subsequently request to make use of them. The main issue is who should bare the risk (and cost) of the assets if the connecting customers do not emerge. While we did not raise this as a specific issue in our

September strategy consultation, we have received significant stakeholder feedback that current policy prevents the timely roll out of capacity for large development schemes.

Our decision

3.53. We do not consider that changes need to be made to the legal or regulatory framework in order to provide DNOs with greater freedom to undertake strategic investment. Under our current approach to cost assessment, we are open to DNOs submitting a case for strategic investment in their business plans, on a project by project basis, which appropriately shares the risk of stranded assets between themselves, connecting customers and DUoS customers.

3.54. One way of doing this could be to assemble a consortium of customers who wish to make use of strategic investment. DNOs can sign a Section 22 arrangement[10] with the consortium. This would commit them to pay their share of the costs (under the current charging rules) once the assets are installed. Under the Electricity (Connection Charging) Regulations, customers in this consortium can be reimbursed within five years if additional future customers make use of remaining capacity created through the strategic investment.

3.55. In addition, if DNOs can demonstrate to Ofgem that there are benefits to DUoS customers of a strategic approach, then we will consider allowing DUoS customers to fund up to the level they would have done under an incremental approach. In practice, we would expect DNOs to pass some of the cost benefits on to DUoS customers in recognition of the increased risk they are taking.

Stakeholder feedback

3.56. DNOs have indicated that they cannot take the risk of investing strategically and prefer to wait for specific connection requests and develop the network in an incremental manner. If a large volume of demand does emerge over time, the overall costs of connecting it may be larger under an incremental approach. Some customers may also experience delays in connection.

3.57. Stakeholders, particularly in London, have expressed concerns that under the current approach, DNOs are not incentivised to think longer term and plan the network strategically. They have commented that this can cause connection delays for high value development projects and that these delays are harming the competitiveness of the GB economy.

[10] Section 22 of the Electricity Act allows customers and DNOs to reach their own commercial terms for connection, outside the auspices of the other requirements of the Act.

Reasons for our decision

3.58. Distribution charging is based on a 'shallowish' connection policy. This means that connecting customers pay for any sole use assets plus a proportion of any reinforcement on shared use assets up to one voltage level above the point of connection.[11] DUoS customers pay for the remaining costs of reinforcement of shared use assets. This approach provides an incentive on connecting customers to locate where there is existing spare capacity so that they do not pay a share of any reinforcement costs. This helps to ensure the network develops in an efficient manner. These principles are enshrined in primary legislation which only gives DNOs the right to charge connecting customers for spare capacity if that spare capacity was created through connecting an initial customer.[12]

3.59. In the vast majority of cases the current legal and regulatory requirements drive efficient outcomes. They incentivise customers to connect where there is spare capacity and to consider alternative commercial arrangements such as those involving demand side response (DSR), in order to reduce their connection charge. We consider that DNOs should be reluctant to gamble on investments with DUoS customers' money. We also recognise that DNOs are not financed to take this risk.

Distributed generation

Introduction

3.60. During the RIIO-ED1 price control period it is expected that increasing volumes of (largely renewable) generation will connect to the distribution network. As customers of the DNOs, distributed generation (DG) developers should receive a good level of service and low cost connections. The connection of renewable DG will be important in contributing to the UK's carbon emissions targets. In RIIO-ED1 there will be a range of incentives and mechanisms to encourage DNOs to better facilitate the connection of DG to the network.

Our decision

3.61. We have decided not to retain the DPCR5 DG incentive mechanism. DG will be treated in the same way as demand. We set out below the reasons for our

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[11] This proportion is determined by the cost apportionment rules which are set out in the common connection charging methodology (CCCM).
[12] Section 19.2 of the Electricity Act (1989). The Electricity (Connection Charging) Regulations sit under the Electricity Act and state that DNOs can recover costs within 5 years of the initial connection. Where the initial connectee 'wholly or mainly' contributed to cost of the works, the regulations compel the DNO to charge subsequent connectees who make use of the capacity and return a proportion of these charges to the initial customer.

decisions, including the RIIO-ED1 mechanisms which will better encourage the DNOs to be proactive and engage with DG customers.

Summary of consultation proposals

3.62. The DG incentive was introduced in DPCR4. We introduced this mechanism to incentivise DNOs to invest efficiently in reinforcement required to connect an uncertain volume of DG. It did not, however, encourage DNOs to connect DG per se. The DG incentive was primarily an uncertainty mechanism and an incentive on capex efficiency. In the September strategy consultation we proposed to remove the DG incentive. We considered that other mechanisms in the proposed package would appropriately incentivise DNOs to efficiently connect an uncertain volume of DG.

Summary of consultation responses

3.63. The majority of DNOs agreed with our proposal to remove the DG incentive for RIIO-ED1. Of these, some were keen to see additional mechanisms to manage uncertainty, and one DNO wanted the DG incentive retained. DG customers raised concerns over the level of uncertainty the DNOs face in forecasting DG connection volumes and associated reinforcement costs, and the strength of incentives for DNOs to facilitate or enable the connection of DG customers.

Reasons for our decision

3.64. With the RIIO-ED1 package, we want to encourage DNOs to facilitate DG connections and provide a good level of service to DG customers. We also want to ensure that efficient investment is strongly incentivised in order to provide low cost connections and reduce costs for DUoS customers. This package should enable DNOs to respond appropriately to demands from DG customers, in terms of volume of connections, the associated cost, and service requirements. We also believe that this package will encourage the use of more innovative alternatives to traditional reinforcement to facilitate DG connections.

3.65. We believe that the range of mechanisms in RIIO-ED1 that will apply to DG customers and connections will adequately address the concerns raised by respondents. Feedback from the DG community has indicated that the perceived complexity of previous arrangements has sometimes been a barrier to engagement with DNOs and investment. We believe that by removing the DG incentive, the treatment of DG in the price control should be simplified in comparison to DPCR5.

Interaction with DG customers

3.66. In connections, DNOs should be customer-facing businesses and therefore should be concerned with their level of service. DG customers should receive a good level of service from DNOs across a range of services and activities. In RIIO-ED1 there will primarily be three mechanisms designed to promote this.

3.67. DNOs should be incentivised to provide a good connections service to DG customers. The Incentive for Connections Engagement (ICE) will require DNOs to provide good customer service where there is insufficient competition in the connections market to drive this behaviour. DNOs will need to set requirements for interacting with different types of connection customer. DG customers can work with the DNOs to develop requirements that are appropriate for their needs. Failure to meet these requirements will lead to DNOs facing a financial penalty.

3.68. Guaranteed Standards of Performance (GSOP)[13] in connections ensure that DNOs meet minimum timescales for the delivery of specified connections services. If the DNO fails to meet the prescribed standard, they must pay compensation to individual customers.

3.69. The Broad Measure of Customer Satisfaction (BMCS)[14] should encourage DNOs to improve the quality of their customer service by capturing and measuring customer contacts with their DNO across a range of services and activities. It will be retained for DG customers for RIIO-ED1 in relation to non-connection related activities only (ie complaint resolution and stakeholder engagement). To incentivise improvements to the connection service provided for DG, the connections element of the BMCS will be replaced by the ICE where there is no effective competition.

3.70. While the minimum legal requirements provide a level of standardisation across DNOs in their interactions with DG customers, we expect DNOs to work with all stakeholders to implement innovative solutions. In addition, networks are not homogenous and therefore it is expected that different solutions are applicable in different locations, and for different customers. However, despite the range of approaches we anticipate, the range of incentives on DNOs should drive behaviours that are of benefit to DG (and demand) customers.

Cost of connecting DG

3.71. The cost of connecting DG customers has three elements (using the same methodology as for demand connections): sole use, shared use and DUoS. For sole use assets, DNOs are required to offer the minimum cost scheme to connecting customers. The connectee pays the whole cost of the sole use assets as these are only for the use of that specific customer. Where network reinforcement is required to make the connection, the cost of the reinforcement is split between the connecting customer and DUoS customers

[13] Set out in more detail in Chapter 8.
[14] Set out in more detail in Chapter 6.

in proportion to the percentage of maximum capacity required by the connectee.

3.72. The expenditure on network reinforcement to facilitate the connection of DG customers is covered by three elements. DNOs are funded through an ex ante allowance for the efficient investment required to connect their forecast volume of connections. Through stakeholder engagement, DNOs will develop forecasts of volumes of DG connections and related reinforcement expenditure. DNOs will benefit from accurate and justified forecasts of DG connections and are therefore incentivised to engage constructively with the DG community.

3.73. Actual expenditure on network reinforcement will be included in the load related expenditure reopener to protect DNOs and customers from uncertainty in the investment forecasts. For further information on the load related expenditure (LRE) reopener, see 'Supplementary annex – Tools for cost assessment' and 'Supplementary annex – Uncertainty mechanisms'. Including expenditure in the LRE reopener will protect DNOs from significant changes in the volumes of DG connections they have to facilitate. Whether this is due to policy changes, reducing costs of DG developments, or other factors, this protection should enable DNOs to respond to the volume of connections the DG community requires. Furthermore, in comparison to the start of the DPCR5 price control period, DNOs should now have greater experience of forecasting and managing DG connections.

3.74. DNOs are incentivised to ensure the reinforcement costs arising from connecting DG (and demand) are efficient through the efficiency incentive. The existing DG incentive provided cost efficiency incentives on 20 per cent of capex and the remaining 80 per cent of capex was passed through. DNOs faced a maximum of 20 per cent efficiency incentive, but no incentives on opex. In RIIO-ED1, DNOs will be incentivised on 100 per cent of totex (total expenditure, the combination of capex and opex). This has two key impacts which are of benefit to the DG community. Firstly, as DNOs will be incentivised on a higher proportion of expenditure, the incentive to reduce costs is increased. Secondly, by equalising incentives on capex and opex, DNOs will be incentivised to implement smart solutions in instances where they are lower cost as these can be opex rather than capex dominated. These increases in cost efficiency incentives should lead to cheaper and more innovative connection offers for those connections requiring upstream reinforcement.

Assessment and design (A&D) fees

3.75. In the September strategy consultation we stated that we consider that a reduction in speculative connection applications could enable DNOs to provide better service to connection customers. At present, in the absence of regulations under the Electricity Act 1989 (the Act), DNOs are unable to charge for assessment and design (A&D) fees in advance of the customer accepting a formal connection offer. As such, many customers use the connection quotation process as a method of collecting information.

Consequently, A&D costs for customers that accept connection offers are increasing and the number of applications is causing delays in the provision of quotations.

3.76. Reducing the number of speculative requests will enable DNOs to devote more time to each application and proceed with the certainty that the application is genuine. This would allow them to fully consider the connection options, including smart grid solutions, which may provide quicker and lower cost means of connection. It could also allow DNOs more time to discuss the specific requirements of certain customers (eg DG and the best way to accommodate them).

3.77. Responses to the September strategy consultation from the DG community, DNOs and other stakeholders showed support for the introduction of appropriate and reasonable A&D fees. Providing DNOs are able to demonstrate the direct benefit to customers of introducing upfront A&D fees, Ofgem will support an application to DECC to make the necessary regulation under the Act to charge for A&D upfront. Industry is currently working to develop a cost benefit analysis to demonstrate the benefit customers will see as a result of any new regulations.

4. Reliability and safety

Chapter Summary

This chapter summarises our decisions for the output areas of reliability and safety in RIIO-ED1. It gives an overview of the primary outputs, secondary deliverables and incentives in these two areas. It also sets out how Climate Change Adaption should be approached in this area.

We have set out full details of our decisions and the reasons for them in the 'Supplementary annex – Reliability and safety'.

Introduction

4.1. The long-term safety and reliability of the electricity distribution networks and their impact on customers are key priorities for Ofgem. Customers expect the DNOs to maintain a safe network while minimising the number and duration of supply interruptions. We also expect DNOs to use their price control funding to prevent longer-term deterioration of the network.

4.2. Whilst working to improve reliability and restoration, DNOs must maintain compliance with their overall requirement to ensure that their networks are designed and operated in a way that ensures the safety of the public and their employees.

4.3. This chapter summarises the decisions we have made in the area of reliability and safety as well as setting out a high level summary of responses. The 'Supplementary annex - Reliability and safety' explains our decision in each area in greater depth and sets out the specific proposals consulted on in September, summarises responses to these proposals and explains the reasons for our decisions.

Health and safety

4.4. Our decision is that the appropriate primary output for health and safety is compliance with the safety requirements set out in legislation and enforced and regulated by the HSE. We have decided not to introduce any financial incentive.

4.5. We are introducing secondary deliverables which have an element of safety performance embedded within them. These are the asset health indices, criticality indices, and composite risk indices. These indices provide a framework for managing network risks including some safety implications and provide a useful means of monitoring and ensuring that the DNOs' compliance with future safety requirements is not put at risk by decisions made during RIIO-ED1.

4.6. As we set out in our consultation, DNOs must comply with all health and safety legislation. The HSE enforces regulations that are contained within this and has powers to secure compliance with the law. Our views that our primary output and secondary deliverables should therefore support rather than duplicate the HSE's functions. Our decision not to apply a financial incentive is also consistent with the RIIO principles which set out that we will not use automatic financial mechanisms that could have a detrimental effect on safety.

Reliability

Introduction

4.7. Customer research indicates that the reliability of supply remains the most important output category for customers.[15] We will continue with the DPCR5 package of outputs and incentives to drive the DNOs to ensure their networks are reliable both in the short and long term. This package consists of:

- Interruptions Incentive Scheme (IIS) – DNOs are incentivised on the number and duration of network supply interruptions versus a target derived from benchmark industry performance

- guaranteed standards of performance – customers are eligible for direct payment of specific fixed amounts where a DNO fails to deliver specified minimum levels of performance

- worst served customers - DNOs have access to funding to improve the reliability performance experienced by a subset of customers experiencing a specific level of interruptions. This funding is given on the condition that the specific customers experience a specified improvement in service

- health and load indices – these are secondary deliverables designed to tie specific price control network investment to specific in-period risk reduction associated with the condition and loading of assets. These metrics encourage longer-term strategies by linking the longer-term reliability benefits of healthier and less highly-loaded assets to a measurable deliverable within the price control

- resilience - refers to the ability of the electricity distribution networks to continue to supply electricity to customers during disruptive events, such as floods, or severe storms. DNOs are required to design and operate their

[15] Report for the Ofgem Consumer First Panel Year 4: http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1ConResConsumerPriorities.pdfhttp://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1ConResConsumerPriorities.pdf

networks in accordance with relevant statutes, codes and standards (such as Engineering Recommendation P2/6). For RIIO-ED1 we have decided we will monitor and publish performance secondary deliverables for each of the areas of flooding, Black Start (which refers to actions necessary to restore electricity supplies following total or widespread shutdown of the GB transmission system) and overhead lines under the overall banner of Network Resilience.

Interruptions Incentive Scheme

4.8. We are retaining the Interruptions Incentive Scheme (IIS) in RIIO-ED1, with some modifications to the DPCR5 scheme.

Incentive rates

4.9. We have aligned the IIS incentive rates with those proposed as part of the RIIO-T1 Energy Not Supplied incentive. We have decided that the efficiency incentive should be applied to these rates.

4.10. These changes ensure that the IIS incentive rates best reflect the value that customers put on supply interruptions.

Revenue exposure

4.11. We have decided that the overall revenue exposure to the IIS will be 250 RORE basis points per annum.[16] This will be symmetrical, meaning that 250 RORE basis points will be the maximum reward or penalty available in each year of RIIO-ED1.

4.12. We believe that this range is more reflective of credible DNO performance ranges than the higher ranges put forward within the September strategy consultation.

Targets

4.13. We have decided to separate planned and unplanned targets to provide clarity for stakeholders and due to the fact that there are different methods used to calculate planned and unplanned targets.

[16] This will be converted to a fixed £m value which will be set out in the licence.

Planned target setting

4.14. A certain level of planned interruption will inevitably be required to allow for the necessary asset expenditure plans in RIIO-ED1. As customers are inconvenienced less by planned outages, where sufficient notice is given, we will weight the incentive on these interruptions at 50 per cent relative to equivalent levels of unplanned interruptions.

4.15. Annual DNO targets for planned interruptions will be set at the annual average level of planned interruptions and minutes lost over the previous three year period. There will be a two year lag on the years utilised in setting the target, so the starting 2015-16 target would be the average annual performance over the 2011-12 to 2013-14 period. This three-year average performance rolling target will update on an annual basis. DNOs will be rewarded or penalised based on the difference between their actual performance and the target, using the incentive rate that is half that of unplanned interruptions.

4.16. DNOs can propose alternative targets for their planned interruptions in their well-justified business plans. Proposals should include justification for why targets should differ from those we have set out.

Unplanned target setting

4.17. We have decided to set unplanned targets for each DNO up front, in advance of RIIO-ED1 using the same methodology as indicated in the September strategy consultation. We have decided to use data up to 2012-13 for setting unplanned targets for all DNOs. In Appendix 2 of 'Supplementary annex – Reliability and safety' we set out indicative targets for RIIO-ED1. These have been set using the methodology we will be using for RIIO-ED1 targets, but without the future performance figures that will be included in the setting of the final targets.

4.18. DNOs can propose alternative targets for unplanned interruptions in their well-justified business plans. Proposals should include justification for why targets should differ from those we have set out.

Exceptional events

4.19. Particular large interruptions can occur that DNOs have limited ability to prevent. In order to reduce the volatility and impact of these occurrences on their performance (and future target setting), these exceptional events are excluded from annual performance figures. Exceptional events are classified as being either a severe weather exceptional event or a one-off exceptional event.

4.20. A severe weather exceptional event is where a minimum, verified, number of higher voltage interruptions directly caused by bad weather have occurred within a 24 hour period. The minimum number is referred to as the severe weather exceptional event threshold.

4.21. As proposed in the September strategy consultation, we have decided to maintain this severe weather exceptional event threshold at eight times the average daily fault rate at higher voltage. The indicative threshold numbers using data including the 2011-12 reporting year are presented in Appendix 2 of 'Supplementary annex – Reliability and safety'.

4.22. One-off exceptional events refer to a single cause outside of the DNO's control causing a significant level of interruption. To be considered a one-off event, a specific and verified number of interruptions and/or minutes lost are required to have resulted. These numbers are referred to as the one-off exceptional event thresholds.

4.23. We have decided to maintain the one-off exceptional event thresholds of 25,000 customers interrupted and two million customer minutes lost.

Cut-out failures

4.24. We have decided not to include interruptions resulting from a single premise cut-out fault within the IIS. This is primarily driven by concern over the robustness of the relevant historical data and its suitability for setting targets. We have put in place improved reporting during DPCR5 which will allow us to explore the possibility of introducing these failures into the IIS as part of RIIO-ED2.

Short interruptions

4.25. Having explored the possible approaches to incentivising the reduction of short interruptions, we have decided that it is not appropriate to implement such an incentive for RIIO-ED1. This is based on our research on customer willingness to pay, and awareness of the potential for adverse interactions and overlaps between a scheme to reduce short interruptions and the IIS.

Guaranteed Standards of Performance

4.26. We have decided to amend the guaranteed standards relating to quality of network service, Statutory Instrument (SI) No. 698, 2010[17] as follows:

[17] http://www.legislation.gov.uk/uksi/2010/698/pdfs/uksi_20100698_en.pdf

- the 18 hour normal weather interruption duration standard will be reduced to 12 hours
- the Highlands and Islands exemptions from specific guaranteed standards will be removed
- the DNO exemption from paying out in the event of a one-off exceptional event will be removed
- the specific levels of payment identified within SI No. 698, 2010 will be up-rated in line with the forecast inflation rate to the midpoint of RIIO-ED1 (2018-19) and rounded to the nearest £5.

4.27. The guaranteed standards relating to severe weather will continue as in DPCR5. The exceptional event thresholds for the guaranteed standards will continue to be aligned with the IIS severe weather thresholds, as outlined above in paragraphs 4.19 and 4.21.

4.28. Payments to customers on the priority service register should be made automatically, as DNOs will be aware of when, and for how long, they have been interrupted.

4.29. We do not expect DNOs to make automatic payments to other eligible customers that are not on the priority service register. As DNO systems are currently unable to individually identify which premises are impacted by individual interruptions, customers will still need to apply to their DNO for payments. Until smart meters are rolled out we do not think it is appropriate to expect DNOs to make payments to these customers automatically.

4.30. DNOs are encouraged to set out in their business plans their proposals on how they can better inform their customers of their eligibility for payment, as well as raising awareness of the guaranteed standards among their customers by providing clear links on their website. This should ensure that eligible customers are more aware of their entitlements under the guaranteed standards. To further encourage payments to be made to eligible customers, we have decided to apply a penalty rate on unpaid compensation.

4.31. The changes that we have made to the guaranteed standards were widely supported by stakeholders, particularly the reduction of the normal weather standard from 18 to 12 hours, and the removal of the exemptions covering the Highlands and Islands and certain circumstances for one-off exceptional events.

Worst served customer mechanism

4.32. We have decided to retain the current mechanism to provide a conditional allowance on a use it or lose it basis that requires DNOs to improve the reliability of service experienced by customers experiencing a service significantly worse than the majority of customers.

4.33. We have made modifications to aspects of the existing scheme, permitting DNOs to propose appropriate parameters to particular areas that have previously been prescribed by Ofgem. An overall allowance of £76.5m will be distributed across DNOs in line with the number of qualifying customers in each region. Within the constraints of this allowance, based on engagement with relevant stakeholders, and likely solution costs, DNOs will be able to propose an appropriate cap on the expenditure per customer covered by the scheme, as well as the service improvement that these customers will experience.

4.34. Further details of our decision on the worst served customer mechanism are set out in Chapter 8 of the 'Supplementary annex – Reliability and safety'.

Secondary deliverables

Load Index (LI)

4.35. The LI provides a measure of the loading of the substations on each DNO's primary network.

4.36. We have worked with industry to develop greater consistency in calculating loading and the classification of substations into LI ratings. We set out the classifications for the LI1 - LI5 ratings that are to be used in business plans within Chapter 5 of the 'Supplementary annex – Reliability and safety'. We have decided that the DNOs' business plans will set out the funding that they will need to deliver a specific level of loading across their substations, rather than being funded for a specific level of improvement. Chapter 5 of 'Supplementary annex – Reliability and safety' also sets out how the impacts of distributed generation (DG) growth are to be captured in the LI framework.

Health, criticality and risk indices

4.37. Health and safety compliance must remain the priority for DNOs when developing their business plans and making investment decisions. The health, criticality and risk indices are secondary deliverables which we will use to assess changes in the respective position of DNOs' networks in these areas over time.

4.38. We have decided to modify the existing health index (HI) by stripping out the criticality element and creating a separate criticality index, measured on a scale of C1 to C4 which will include criticality elements not previously embedded in the HI. We believe this will allow DNOs to more clearly demonstrate that actions taken by them during RIIO-ED1 to reduce network risk take account not only the probability that an asset fails, but also the expected impact of such failures.

4.39. The health and criticality scores for relevant assets will be combined and consolidated into a newly developed composite risk index. Using DNOs' forecasts for their network's position according to the risk index, we will be able to determine an asset risk score improvement or delta, which will represent the DNOs' agreed deliverable for RIIO-ED1. We believe that such a framework will enable us to quantify improvements over time and provide sufficient flexibility for DNOs to pursue asset management practices they deem to be most appropriate for their networks.

4.40. At the end of RIIO-ED1 the risk index will attract a reward or penalty for material over or under delivery. This incentive mechanism will contain two elements. If a DNO has not delivered the agreed total asset risk score improvement and does not have a reasonable justification for doing so, a downward adjustment to their RIIO-ED2 allowed revenue will be applied. The DNO will also be subject to a penalty of 2.5 per cent of the value of the under delivery. Conversely, where a DNO has delivered more than the agreed total asset risk score improvement, and this improvement has been justified, an upward adjustment to their RIIO-ED2 allowed revenue will be applied. The DNO will also receive a reward of 2.5 per cent of the value of the over delivery. Consultation respondents agreed with our proposal to include a financial incentive mechanism and we believe it will help to drive good asset management practice through efficient and timely investment decisions over the course of RIIO-ED1.

Resilience

4.41. We have decided that for RIIO-ED1 we will monitor and publish performance against specific secondary deliverables relating to resilience. For each of the areas of flooding, Black Start and overhead lines, we will track DNO performance in removing risk against the level of risk reduction provided by their agreed settlement.

4.42. High impact, low probability (HILP) events are extreme events which could potentially result in the prolonged loss of electricity supply. The impact of such events are beyond the level of credible first or second outage event impacts, which distribution networks are designed to ensure high levels of security of supply for. For HILP events, we will maintain the option for the government to provide guidance to us on what work is required by the DNOs and whether this should be funded through the price control. If this is forthcoming during RIIO-ED1 we will work with the government and DNOs to ensure that any investment is made efficiently, taking into account all available options and the benefits delivered by these. This will potentially involve introducing a HILP metric. Responses to the consultation were in favour of this approach.

Climate change adaptation

4.43. Climate change is likely to have an increasing influence on both average conditions and the frequency and severity of extreme weather in the UK. This could have an adverse impact on DNOs' safe and reliable operation of their networks, without appropriate risk management measures being put in place. This is particularly relevant for those assets which DNOs expect to be in operation for several decades.

4.44. The main factors affecting electricity networks from current climate change projections are:

- hotter average and extreme temperatures, particularly in summer
- more rain in winter and more extreme downpours all year – leading to a greater risk of flooding
- rising sea levels and greater storm surges – leading to a greater risk of coastal flooding.

4.45. The potential impacts of these changes are described in more detail in the Energy Network Association's (ENA) 'Energy Networks Climate Change Adaptation Report' (2011).[18]

4.46. We expect DNOs to present evidence for how risks to their networks from extreme weather and climate change have been assessed using the latest climate projections and science. DNOs should also explain how they plan to manage climate risks to make sure that new and existing schemes are sustainable. DNOs' business plans should set out:

- the risks climate change pose to their services
- how these risks have been assessed
- what options have been influenced by climate change, and how resilient these options are to different climate change projections.

4.47. The specific assets and areas of investment that we would expect DNOs to consider in regard to these risks and more broadly their networks' overall resilience, would include the following:

- flooding resilience
- overhead electricity lines eg overhead line ratings and structural strength of supporting structures
- vegetation infestation eg changes in growing season prompted by climate change
- underground cables eg the impact of climate change on cable ratings
- substation earthing eg the impact of climate change on earth resistance
- transformer and substation resilience.

[18] http://www.defra.gov.uk/environment/climate/sectors/reporting-authorities/reporting-authorities-reports/

4.48. Climate change cannot be used to justify investment in unnecessary infrastructure. If business plans include a need for greater investment to cope with climate change, DNOs should justify how the extra investment will save money and protect services in the future. This may involve cost benefit assessments (CBA) for potential issues, in order to determine the most appropriate investment strategy. Our approach to CBAs is set out in Chapter 5 of 'Supplementary annex – Business plans and proportionate treatment'. Where appropriate, this will include our assessment of customers' willingness to pay for adaptation measures, and take into account any wider societal aspects. Sometimes it may be appropriate for a DNO to delay investment in some measures to reduce climate risk, but ensure that it leaves these options open so it has the ability to respond flexibly and employ them should future needs demand this.

Reliability and Safety

Summary of consultation proposals

4.49. A full summary of the proposals for each area is included in the relevant chapters of the 'Supplementary annex – Reliability and safety'.

4.50. In the 'Supplementary annex – Outputs, incentives and innovation' of the September strategy consultation, we asked respondents for views on our proposals for primary outputs and secondary deliverables and whether they agreed with the areas we had focused on.

Summary of consultation responses

4.51. Respondents were in agreement with our focus in terms of areas covered by primary outputs and secondary deliverables.

4.52. There were some concerns raised over the proposal to reintroduce the upside cap on the IIS and applying the criticality measure to a wide scope of assets unlikely to be replaced within RIIO-ED1.

4.53. One respondent was concerned that moving towards a more standardised approach to the Load Index would drive particular DNOs to become more risk-averse and invest, rather than optimising assets usage for customers.

Reasons for decision

4.54. For detailed reasons for our decisions, please refer to the 'Supplementary annex – Reliability and safety'.

5. Environmental impacts

Chapter Summary

This chapter sets out our decision on the outputs that the DNOs will need to deliver to ensure that they manage their environmental impact and contribute to meeting Great Britain's (GB) broader environmental goals.

Background and context

5.1. The RIIO framework requires companies to reduce their business environmental impact (the narrow environmental objective) as well as contribute to meeting GB's environmental targets (broader environmental objectives). In our September document, we proposed environmental outputs to meet the RIIO criteria to address these objectives.

5.2. In this chapter we set out our decisions on:

'Narrow' environmental impacts

- electricity losses on the distribution network
- electricity theft
- Business Carbon Footprint (BCF)
- sulphur hexafluoride (SF_6)
- fluid filled cables (FFC)
- noise reduction

'Broad' environmental impacts

- undergrounding in Areas of Outstanding Natural Beauty (AONB) and National Parks (NPs)
- environmental discretionary reward.

Electricity losses on the distribution network

5.3. Electricity losses are an inevitable consequence of transferring energy across electricity distribution networks. Electricity losses are a significant source of greenhouse gas (GHG) emissions. Effective losses management also protects customers from unnecessary cost increases. DNOs do not pay for electricity lost on their network and therefore have no inherent incentive to manage losses efficiently. We believe that a strong incentive is required to ensure that DNOs place an appropriate level of focus on losses reduction activities. We consider that the approach detailed below offers the best way of driving down losses.

Our decision

5.4. Our decision is to implement a losses reduction mechanism consisting of four components: licence obligation, loss reduction expenditure in the business plans, annual reporting and discretionary reward. These components will work together to provide a strong incentive for DNOs to manage losses efficiently.

Licence

5.5. We will place a licence obligation on DNOs requiring them to design and operate their networks to ensure that losses are as low as reasonably practicable. This will sit alongside the DNOs' overarching obligation to develop and maintain an efficient, co-ordinated and economical distribution system. This, together with our approach to the use of cost benefit analysis outlined below, should ensure that DNOs manage the losses on their networks efficiently and that any loss reduction measures are justified.

5.6. The licence will provide for Ofgem to be able to audit a DNO's losses reduction activities. Any enforcement would be similar to that taken for any other breach of licence.

Business plans

5.7. DNOs will be required to set out in their business plans their approach to losses reduction in support of their licence obligation. This strategy statement should demonstrate their overall approach, as well as set out specific projects or actions, with timescales and deliverables and an assessment of their impact on losses and the associated additional costs. It may be necessary to update this strategy within the RIIO-ED1 period. We therefore expect the DNOs' strategy statements to set out their proposals for reviewing and updating their losses reduction strategy within the price control period.

5.8. DNOs should include low loss equipment expenditure and other proposed actions to reduce losses in their business plans. This should be justified by considering the losses reduction actions and associated benefits (eg carbon abatement) in companies' whole life costing and cost benefit analysis (CBA). In Chapter 5 of the 'Supplementary annex – Business plans and proportionate treatment' we set out the common CBA approach which we expect DNOs to use to justify expenditure. We will provide guidance on the valuation of lost energy and carbon abatement. We note that certain EU initiatives may lead to obligations which will impact on the DNOs' actions and expenditure in this area. However, we expect that the DNOs will identify and analyse the net benefit of all practicable loss reduction measures, ensuring that their consideration is not limited to any potential EU obligation.

5.9. DNOs should demonstrate in their business plans a thorough understanding of how losses can best be managed across their networks, as well as how they propose to ensure that best practice is shared within the industry. We also expect them to set out proposals for establishing a reliable baseline of losses during RIIO-ED1 as it is our intention to consider a robust losses incentive for RIIO-ED2. Companies should consider how power system modelling, innovative approaches, sharing of best practice and shared initiatives could assist in this process.

Annual reporting

5.10. We will also require DNOs to report annually on their losses reduction activities undertaken in the year, setting out improvements achieved in the year and cumulatively, and actions planned for the following year. The reporting will be linked to the CBA of relevant actions.

Losses discretionary reward

5.11. We will introduce a losses discretionary reward (DR) of up to £32m across all DNOs, awarded in three tranches over the eight years (one tranche of up to £8m in year two, a second tranche of up to £10m in year four, and a final tranche of £14m in year six). The aim of this DR is to encourage DNOs to undertake additional losses reduction actions over and above those set out in their business plans. For example, these might include identifying more cost effective and innovative ways of utilising the allowed revenue to enhance the reduction of losses.

5.12. We are minded to adopt a scorecard approach to the DR. We expect industry to work with us to develop the criteria and key strategic and operational objectives against which DNOs' performance will be measured and scored and will consult on this in due course. The categories against which the DNOs' performance may be measured include:

- companies' understanding of their losses and preparation for a measurable losses incentive in RIIO-ED2
- effectiveness of actions taken to reduce losses, including any actions which have achieved losses reductions which are substantially greater than those forecast
- the demonstrable engagement of DNOs with their stakeholders (eg connection customers, supply chain partners) on losses
- innovative approaches to losses reduction (outside of any projects funded through the innovation stimulus mechanisms)
- performance against the strategy set out to address losses
- sharing of best practice with other companies.

5.13. DNOs wishing to participate in the DR will be required to submit evidence against the scorecard criteria. The criteria could be weighted differently over the three tranches. Ofgem will assess the submissions, with expert advice where necessary, and make recommendations to the Authority. We will ensure that a DNO is not rewarded multiple times for the same actions, but only rewarded for additional actions undertaken.

5.14. We note that the testing of innovative approaches to reducing losses may be eligible for funding under the innovation stimulus mechanisms (Chapter 10), in circumstances where they meet the relevant criteria.

Summary of consultation proposals for losses reduction mechanism

5.15. We explained in our September strategy consultation that we had an incentive based on measured losses volumes in previous price controls. However, due to ongoing difficulties with data integrity we have recently replaced the mechanism with an enhanced reporting requirement.[19]

5.16. We do not believe that there is currently a reliable source of data common to all DNOs for measuring distribution losses. We therefore proposed that the RIIO-ED1 mechanism should focus on actions undertaken by DNOs which lead to reduced losses.

5.17. We set out three options in our consultation: a duties based approach, a losses allowance approach, and our preferred approach which combined aspects of both. The key components of our preferred approach were:

- a licence obligation
- a requirement for DNOs to set out their losses reduction strategy in their business plans
- overall allowed revenue to include the funding required to undertake the actions justified in the business plans, based on a positive CBA
- an annual reporting requirement setting out losses reduction activities undertaken in the year, a rolling assessment of improvements achieved in the year and cumulatively, and actions planned for the following year.[20]
- a provision for Ofgem to be able to audit a DNO's losses reduction activities
- innovative approaches to reducing losses which meet the relevant criteria could be considered for funding under the innovation stimulus mechanisms
- a losses DR of up to £32m across all DNOs, to be awarded twice during the RIIO-ED1 period in two tranches in years four and eight, to encourage DNOs to find more cost effective and innovative ways of utilising the allowed revenue to enhance the reduction of losses.

5.18. We proposed that DNOs should adequately demonstrate a good understanding of how losses can be minimised across their networks in their business plans.

[19] A more expansive background can be found in the September strategy consultation http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/riio-ed1/consultations/Documents1/RIIOED1SConOutputsIncentives.pdf
[20] This reporting requirement will be similar to the distribution losses reporting requirement currently being finalised in relation to changes to the DPCR5 losses incentive mechanism. For further information see http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=6&refer=Networks/ElecDist/Policy/losses-incentive-mechanism

We also stated that we would also expect them to set out proposals (which could include power system modelling) for establishing a reliable baseline of losses during RIIO-ED1 so that a robust losses incentive could be considered for RIIO-ED2.

Summary of responses

5.19. Seventeen respondents commented specifically on aspects of the proposed preferred option for the losses reduction mechanism. Overall, there was support for the key components of the proposals, although there were some concerns that the mechanism was overly complex. One DNO did not support the approach and would prefer to see the previous (DPCR5) mechanism activated. Another response suggested that penalties for not managing losses should be considered.

5.20. One response suggested that compliance with an appropriate engineering standard could complement the licence condition. Another noted that the licence condition would not necessarily lead to a reduction of overall losses but would need to ensure that increases in losses were minimised.

5.21. Some respondents requested further guidance on aspects of the CBA and forecasting incremental costs attributed to losses actions.

5.22. Some respondents agreed with the amount and frequency of the DR proposals, while others suggested that the fund was too low and/or suggested more frequent awards. Some respondents suggested that the proposed DR be increased substantially, based on proportionality with the RIIO-T1 Environmental Discretionary Reward (EDR).[21] They also noted the importance of ensuring that DNOs are not rewarded more than once for the same action, for example through the allowance, the IQI and the DR. It was also suggested that the DR should also make some provision for sharing of best practice between DNOs.

5.23. One response suggested that the DR should not be awarded in the first three years, since little action would have been achieved and reported on. Thereafter there should be an annual award of £5m from years four to seven with a final tranche of £12m in year eight based on a review of the cumulative impact of actions by that date. Other responses suggested that the DR should be awarded every two years or every year, to maintain momentum.

[21] It was suggested that the losses DR could be anything up to £224m, up to seven times the RIIO-T1 EDR, based on the number of distribution network companies compared to transmission network companies.

Reasons for our decision

5.24. We have balanced the need for a strong incentive to manage losses efficiently with the very real difficulty of accurately measuring distribution network losses and therefore assessing the benefits of any losses reduction measures at this time. Bearing in mind this constraint, we consider that our preferred approach offers the best way of driving down losses.

Licence

5.25. DNOs have a general obligation to develop and maintain an efficient, co-ordinated and economical network, minimising investment and system losses. An additional licence condition to explicitly require consideration of actions to reduce electricity losses will sit alongside this obligation. A materially more prescriptive licence condition setting out specific targets could restrict the DNO's ability to manage their network efficiently, and could conflict with other initiatives such as the low carbon agenda and development of smarter grids, which in some circumstances could lead to increased losses. The introduction of the licence condition is designed to ensure that the most cost-effective approach to optimising losses reduction is followed.

5.26. Subsequent discussions with stakeholders have led us to conclude that linking the licence condition to compliance with an Engineering Standard is not considered necessary, as long as adequate guidance and standardisation on the CBA is given on quantifying losses and the valuation of carbon.

DR

5.27. A number of alternate suggestions for the amount and frequency of the DR were put forward. We have considered the points raised but have not identified a compelling argument to increase the amount of the DR available. We do, however, see merit in changing the frequency of the award.

5.28. In considering the response suggesting increasing the proposed DR in line with the RIIO-T1 EDR, we note that the stated purpose of the RIIO-T1 EDR is to sharpen transmission companies' focus on strategic environmental decisions and organisational and cultural change to facilitate growth in low carbon energy. Reducing losses is only one of many actions which is expected to be considered.

5.29. RIIO-T1 does not contain any specific allowed revenue relating to losses reduction expenditure (other than for the System Operator), whereas the bulk of DNO expenditure to reduce technical losses is likely to be motivated through the allowed revenue in RIIO-ED1.

5.30. We also considered the size of the DR against the potential for DNOs to effect a 0.25 to 0.5 per cent reduction on their current losses position through investment supported by their price control allowance and consider that a reasonable additional improvement could be achieved through the DR. In addition we believe that the continued focus on energy efficiency and carbon abatement, including compliance with the European Energy Efficiency Directive[22], provides a strong incentive for DNOs to undertake loss reduction actions. The DR will provide an additional reputational incentive.

5.31. Uncertainty around substantive criteria for the DR, as well as the concerns raised in ensuring that actions are not funded multiple times (for example through allowed revenue, innovation stimulus and the DR), have contributed to our decision not to increase the amount of the DR.

5.32. We considered all of the suggestions put forward regarding the frequency of the DR in discussion with the working group. There was little support for an annual award due to the administrative burden, but agreement that three tranches would be better than two (years two, four and six, or three, five and seven). Factors that we considered included: what actions we might consider rewarding in each tranche; whether there was justification for varying the amount of each tranche; when data would be available for any assessment; and the specific administrative burden applicable at those times.

5.33. We agreed that there would be limited benefit in having a final tranche occurring in the last two years of RIIO-ED1, due to the administrative and reporting burden overlapping with preparations for RIIO-ED2.

5.34. Although limited data on actions undertaken will be available by year two of RIIO-ED1, the reward in that tranche could be focussed on the overall approach to managing losses and this information would be available. The tranche for this first reward would be proportionately smaller than later tranches. The second, slightly larger tranche in year four would be more focussed on specific actions undertaken, with a final (largest) tranche more focussed on cumulative actions and information sharing undertaken, with a stronger focus on results achieved in preparations for a robust mechanism in RIIO-ED2.

Electricity theft

Our decision

5.35. The arrangements for tackling electricity theft will be dealt with through a separate approach outside of the losses reduction mechanism, in line with the approach set out in our proposals. In particular, we will consult on these arrangements in spring 2013, with a key focus on supplier obligations. Prior to implementing a revised approach, DNOs should maintain their current levels

[22] http://eur-lex.europa.eu/JOHtml.do?uri=OJ:L:2012:315:SOM:EN:HTML

of support for suppliers in identifying and resolving unregistered premises and recovering appropriate costs.

5.36. The core elements of our proposed approach are listed below.

- To require DNOs to tackle theft where a supplier is 'not responsible'. Where possible the link between the supplier and the customer should be maintained. We propose amending the standard conditions of DNO and supplier licences. DNOs should be able to recover their reasonable costs associated with this activity.
- To introduce licence requirements for electricity suppliers, in relation to tackling theft, which are equivalent to our updated proposals for gas suppliers.
- To identify principles for a scheme to address the disincentives that suppliers face in detecting theft. Appropriate proposals (similar to those for the gas market) should be introduced by a code modification.
- To require suppliers to put in place a central service (equivalent to the Theft Risk Assessment Service (TRAS) in the gas market) to analyse data and provide information to suppliers (and network companies) to help them meet their obligations to detect theft.
- Suppliers and DNOs should implement, where appropriate, the additional measures that we identified as supporting the arrangements for tackling gas theft.[23] We consider that these additional measures should be introduced through existing industry code governance arrangements.

Summary of consultation proposals for approach to electricity theft

5.37. Theft of electricity increases the costs paid by customers and can have serious safety consequences. It leads to misallocation of costs among suppliers that can distort competition and hamper the efficient functioning of the market. The amount of theft is unclear but some estimates put it at around £400m per year.

5.38. DNOs do not have specific licence requirements to tackle electricity theft. Some DNOs provide revenue protection services which are used by suppliers to help detect theft and are often helpful in identifying theft proactively.

5.39. The non-activation of the DPCR5 losses incentive and the revised approach in RIIO-ED1 to losses reduction could impact on DNO incentives to support the arrangements for tackling theft. We therefore proposed a package for electricity theft similar to those for tackling gas theft[24]. We consulted on the

[23] These include establishing and maintaining a single, 24-hour theft telephone contact number that members of the public or other third parties could use to report suspected theft. For a full list of supporting measures see paragraph 4.23 in Tackling Theft of Gas: The Way Forward, Ofgem March 2012 (Ref: 35/12)
http://www.ofgem.gov.uk/Markets/RetMkts/Compl/Theft/Documents1/Tackling%20gas%20theft%20decision(1).pdf
[24] http://www.ofgem.gov.uk/Markets/RetMkts/Compl/Theft/Documents1/Tackling%20gas%20theft%20dec

proposed approach and our decision has not deviated from any of the core elements.

Summary of responses

5.40. A number of stakeholders responded directly to the question on the proposed approach to theft. All DNOs and some suppliers broadly supported the approach, while noting that dealing with theft is more of a supplier than a DNO responsibility, and that the link between suppliers and customers should be maintained. One DNO considered that there was no scope for DNOs to participate in any theft initiative outside of their current practices.

5.41. Some DNOs noted that it would be appropriate to maintain the current levels of support to suppliers' theft initiatives until new arrangements were in place. The base costs for investigating and resolving unregistered premises should be recoverable (as they are currently).

5.42. Two suppliers contended that DNOs may be 'double recovering' when unregistered sites are identified and that any value recovered should be fed back through industry processes to reduce the impact on customers. Another stakeholder alluded to existing disincentives for DNOs to address theft and that these should be considered in any approach taken. One stakeholder said that any amended theft arrangements should clearly set out the approach to vulnerable customers.

Reasons for our decision

5.43. Electricity theft was previously included in the losses mechanism because the measurement of losses included energy unaccounted for due to theft. Since the proposed losses mechanism does not measure these units, there is no rationale to continue to include electricity theft in the losses mechanism.

5.44. No stakeholders disagreed with the proposals for addressing theft. Feedback received and issues raised will be considered through the separate theft initiative set out in our decision.

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Undergrounding in areas of outstanding natural beauty (AONBs) and national parks (NPs)

Introduction

5.45. The present non-mandatory undergrounding scheme was first established for electricity distribution in DPCR4. It allows for undergrounding of existing overhead lines in two specific designated areas: AONBs and NPs. The primary objective of this scheme is the protection of visual amenity in line with specific statutory obligations.[25]

5.46. In our September consultation, we considered additional elements to be added or clarified within the scheme: our intention to continue with the same funding pot calculation as for the current Distribution Price Control Review 5 (DPCR5) adjusted for an eight year price control period, the inclusion of National Scenic Areas designation as comparable to AONBs in Scotland, and clarity on the use of the 10 per cent allowance. Finally, we also acknowledged the necessity for continued engagement between stakeholders and DNOs regarding assessment of candidate projects and stakeholder engagement.

Funding pot

Our decision

5.47. We will set the funding pot at £103.6m. This takes account of the extended time period for RIIO-ED1 compared with DPCR5, recent prices and the inclusion of overhead lines in National Scenic Areas (NSAs). We consider that the willingness to pay research we conducted in DPCR5 and the methodology for calculating the funding pot continues to be appropriate.

5.48. Table 5.1 sets out the undergrounding allowance by DNO. This has been calculated in line with DPCR5, and is based on the km of overhead lines to be undergrounded and the number of customers in the DNO licensed region.

Table 5.1: Undergrounding allowance by DNO.

DNO	Number of customers	Total km of overhead lines in designated areas	Allowance £m
ENWL	2,364,446	3,217.0	9.0
NPgN	1,581,420	3,611.8	7.9
NPgY	2,266,464	1,007.9	6.0
WMID	2,462,123	3,947.2	10.2
EMID	2,623,103	662.3	6.3

[25] Electricity Act 1989; National Parks and Access to Countryside Act 1949 (as amended by Environment Act 1995); Countryside and Rights of Way Act 2000

DNO	Number of customers	Total km of overhead lines in designated areas	Allowance £m
SWALES	1,103,465	2,329.3	5.3
SWEST	1,551,046	6,409.9	11.4
SPN	2,247,823	4,567.3	10.5
EPN	3,537,357	1,853.6	9.7
SPD	1,994,241	427.5	4.7
SPMW	1,487,412	3,449.3	7.5
SSEH	745,907	3,122.2	5.5
SSES	2,952,565	2,737.7	9.6
Total	**29,184,812**	**39,355.0**	**103.6**

N.B. Since UK Power Networks (LPN) is almost entirely underground network it is not eligible for the scheme

Summary of our consultation proposals

5.49. In our September consultation, we proposed to use the same calculation for the funding pot and allocation as was used for the current price control. We separately advocated the inclusion of NSAs within the undergrounding scheme, as a comparable designation to AONBs, to help facilitate greater use of the scheme in Scotland.

5.50. We therefore highlighted our intention to include NSAs within the pot and indicated that we were aware that there were elements of double counting that would need to be taken into consideration when calculating the pot with the inclusion of this designation.

5.51. As outlined in our consultation, the willingness to pay research we conducted in DPCR5 focussed on AONBs and NPs but not NSAs. However, as there are relatively few distribution lines crossing NSAs, we considered that the inclusion of this designation, as comparable to AONBs for Scotland, would have a minimal impact on the funding pot and on willingness to pay. Therefore, we were of the view that the current willingness to pay results are still relevant for RIIO-ED1.

Summary of responses

5.52. Respondents welcomed the continued use of the methodology for calculating the funding pot. However, they voiced concerns about us taking account of the results of the willingness to pay research being conducted by transmission network companies for the purposes of RIIO-T1, and the potential for dilution of the pot given the inclusion of NSAs.

5.53. However, there was general agreement for including NSAs on the same basis as AONBs. One respondent suggested that this would not guarantee uptake of the undergrounding scheme in Scotland as the scheme is not compulsory.

5.54. One respondent noted that there was a risk of double counting where some NSA designations fall into existing National Parks.

5.55. Another respondent also advocated ensuring that the formula should allow the distributor to consider higher voltage lines that have a particularly high negative impact on the landscape. Another response mentioned the inclusion of metal towers within the scheme.

Reasons for our decision

5.56. In our consultation, we indicated our expectation that DNOs would provide clear evidence on the location and designation of undergrounding schemes to ensure that there was no double counting between overlapping National Parks and NSAs.

5.57. We consider that by including the NSA designation, we are facilitating greater access for interest groups in Scotland. The number of overhead distribution network lines in NSAs appears to be relatively small and thus has a minor impact on the total funding pot.

5.58. In response to one particular respondent, it should be noted that the pot does not discriminate between voltage levels, or against metal towers. Under DPCR5, we removed the voltage caps that were previously set within the mechanism and this will be continued into RIIO-ED1. The structure of the scheme is such that interest groups and DNOs cooperate to allocate funds to projects in the most cost effective manner to maximise visual amenity benefits in the designated areas.

5.59. Furthermore, in response to comments regarding the non-compulsory nature of the scheme, we consider that the mechanism works well and in some areas there is very active stakeholder involvement. We acknowledge that there are areas where smaller stakeholder groups suffer resource constraints and therefore may not be as involved as in other areas. However, we feel it is against the spirit of the scheme to compel DNOs to take part. We encourage DNOs to engage with their local stakeholders and consider potential projects in their regions that could be addressed through this scheme.

5.60. In our consultation we indicated that we may take into account, where relevant, the results of any future studies on willingness to pay conducted under RIIO-T1. We are aware that the criteria for these studies are different to those we would consider under RIIO-ED1 and that the investment decisions on the transmission system would be on a different scale to those in distribution. However, we are interested in the criteria and views of consumers with regard to these larger scale investments in undergrounding.

10% allowance

Our decision

5.61. The 10% allowance provision was included as part of DPCR5 to encourage flexibility and cooperation with the scheme. In continuing with this provision for RIIO-ED1, we have decided to provide best practice guidance outlining specific instances where the allowance has been used effectively.

5.62. We will ask DNOs to provide us with examples and will collate and publish these as best practice examples. Thereafter, we hope that DNOs continue to cooperate and share new best practice examples of cooperation between each other and with their stakeholders. In addition, we intend to promote the benefits of the undergrounding scheme within specific public documents which we publish on our website.[26]

Summary of our consultation proposals

5.63. In our September consultation, we acknowledged that DNOs and interest groups may need clarity on the use of the 10% allowance and so we requested views on whether guidance should be provided and what form this should take.

Summary of responses

5.64. The majority of responses were in favour of continued flexibility within the 10% allowance. Respondents either suggested that no guidance was necessary for fear of limiting flexibility, or suggested high level guidance outlining examples of best practice use.

5.65. Respondents demonstrated a good understanding of the intent of this allowance and instances of its use.

5.66. We also received comments from respondents that the undergrounding scheme as a whole could be better promoted.

5.67. One respondent advocated that the 10% allowance should be extended to undergrounding projects that had an effect on Special Qualities outlined in Lake District National Park policy documents. Special Qualities, we understand, include complex geology, archaeology and particular flora and fauna.

[26] Electricity Distribution Annual Report and Sustainable Development Focus

Reasons for our decision

5.68. We consider that sharing examples of best practice of use of the 10% allowance could encourage stakeholders and DNOs to be able to consider the use of any of these examples for their individual projects as appropriate.

5.69. We agree that the undergrounding scheme could be promoted better and will do so within specific publications which we will issue on our website.

5.70. We consider the structure of the undergrounding scheme, including the 10% allowance, is sufficient for stakeholders and DNOs to consider and agree on the various merits and impacts of particular projects and accommodate any special circumstances of particular projects as appropriate, e.g. Special Qualities.

Assessment policy and stakeholder participation

Our decision

5.71. We expect DNOs to develop, and make available, policies for assessing candidate projects and for interacting and supporting relevant stakeholders as necessary.

Summary of our consultation proposals

5.72. In our consultation, we advocated that DNOs should develop policies outlining how they assess potential undergrounding projects including consideration of competing factors and impacts that any project may have. Furthermore, as a stakeholder-led scheme, we acknowledged that some stakeholders (interest groups or relevant authorities) may not be as forthcoming with undergrounding projects due to lack of resources. We are aware that some DNOs have in certain cases provided a variety of ways to support their stakeholders. We considered that this information should be formalised and shared with stakeholders to allow them to fully engage with the scheme and their DNO.

Summary of responses

5.73. The DNOs welcomed our proposal. They agreed to the need for clear policies being made available on the assessment of candidate projects and stakeholder engagement including, where possible, details of any support DNOs could provide to their stakeholders.

Additional undergrounding comments

The growth and infrastructure bill

5.74. We are aware of the Department of Culture Media and Sport's (DCMS) current consultation, which proposes to relax planning restrictions for overhead broadband lines in protected areas for a period of five years in order to facilitate cheap and fast roll-out of the broadband project.

5.75. We intend our undergrounding scheme to continue as proposed. We have engaged with DCMS, Ofcom and other stakeholders and we understand that they are aware of the potential impact on our undergrounding scheme in situations where incentives are in place for retrospective undergrounding to protect visual amenity and at the same time new services are being installed via overhead lines in order to reach rural communities. We encourage stakeholders to engage with the DCMS consultation process.

Scope of undergrounding

5.76. One respondent advocated that the scope of the undergrounding scheme be extended to include coastal areas and areas of local amenity like village commons. Another suggested that the scheme should be able to include candidate National Park (NP) extension areas.

5.77. A respondent commented on the difficulty of securing consent in non-designated areas for refurbishment of overhead lines in favour of undergrounding.

5.78. We appreciate that there are areas of visual and community amenity that some interest groups feel should be protected and should be within the boundary of the scheme. However, we consider that extending the scope of the scheme would undermine its effectiveness in seeking to protect the specific designations in line with specific statutory obligations.

5.79. The scheme remains open to those areas that are newly designated AONBs (or NSAs) or NPs during the price control period, which may include circumstances where boundaries of existing designated areas are extended, eg NP extension areas.

5.80. In our consultation, we clarified that the scheme does not represent a DNO's entire undergrounding programme. The scheme seeks to incentivise retrospective action to maximise the benefit to visual amenity of undergrounding overhead lines in specific designated areas. Outside of the scheme, the DNO (or a customer) may choose to underground lines for other reasons and fund this through means outside of this scheme. We encourage parties to cooperate to seek alternative funding as appropriate to cover the expense of projects outside of this scheme.

Business carbon footprint (BCF)

Our decision

5.81. We have decided that the scheme, introduced in DCPR5, will remain reputational and that the league table will include details of proactive actions taken by DNOs to reduce their emissions. We will ask DNOs to provide this additional reporting. We will be publishing the first league table and baselines as set for each DNO as part of our Electricity Distribution Annual Report. We will include an option for us to review and for DNOs to reapply for baseline resets once during the extended RIIO price control period.

5.82. In DPCR5, we made clear our intention to use one year's reporting data to set individual baselines for each DNO. We are finalising the setting of the baseline and have agreed that this would be included in the 2011-12 Electricity Distribution Annual Report. Three DNOs came forward with proposals for their baselines to be reset. Going forward into RIIO-ED1, we consider that we may need an opportunity to review baselines, given the extended price control period and that DNOs may wish to seek a reset of their baseline due to actions taken during this price control period. We will indicate a possible point where a review of baselines will be considered during the price control period as part of BCF guidance.

Summary of our consultation proposals

5.83. In our consultation, we proposed to retain the DPCR5 scheme and keep it reputational. We noted that greater detail on proactive actions would be useful for us to understand the positive activities DNOs are engaging in to reduce their emissions.

Summary of responses

5.84. In response to our consultation questions on whether respondents considered that there are any additional elements that should be included in the BCF reporting, some respondents advocated the inclusion of additional elements, eg recycling, or the removal of exceptional events from the scope, or increased detail in the data, eg net or gross.

Reasons for our decision

5.85. BCF is a reputational scheme based on a league table and a baseline. Therefore, the data itself has been kept at a high level in order to allow for comparison between DNOs and, in the future, comparison of a DNO against their set baseline over time.

5.86. We have been clear in our BCF guidance that we expect the GHG Protocols to be the framework under which DNOs report against the BCF and that any specific assumptions and deviations from the protocols need be clearly outlined in reporting packs for BCF. We note that there have been recent Scope 3 guidelines published[27] which DNOs should be aware of in completing any future BCF reporting. Therefore, we do not consider it necessary to include any additional elements or remove existing elements from the mechanism.

Sulphur hexafluoride (SF_6)

Our decision

5.87. We have decided that SF_6 reporting will remain as part of the BCF and that we will introduce enhanced regulatory reporting specifically for SF_6. We consider that DNOs should be preparing themselves for the possibility of increased external obligations and reporting on SF_6 emissions,[28] such as the proposed amendments to the F Gas Regulations 2009 and Greenhouse Gas Emissions (Director's Report) Regulations 2013 being developed by government.

Summary of our consultation proposals

5.88. In our consultation, we proposed that SF_6 reporting should be enhanced within regulatory reporting requirements, including additional forecast data and commentary on mitigation activities as proposed under the BCF.

Summary of responses

5.89. There was general agreement to our approach. One respondent felt that regulatory reporting should not be enhanced if increased external obligations were going to be introduced.

Reasons for our decision

5.90. We consider that SF_6 reporting needs to be enhanced to aid our understanding of the scale of inventories and emissions and how they change over time. We have therefore decided to include forecast data reporting and additional explanatory narrative as part of regulatory reporting.

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[27] http://www.ghgprotocol.org/standards/scope-3-standard
[28] IEC 2271 international standard relating to gas tightness; ENA Engineering Recommendation S38 and/or PAS 55 asset management standard; requirements under Gas Regulations 2009 relating to recovery and maintenance, labelling and end of life disposal and forthcoming amendments to these regulations as relevant.

Fluid filled cables (FFC)

Our decision

5.91. We have decided that the current external Operating Code agreed between the Environment Agency (EA) and the DNOs is sufficient to incentivise the appropriate management of this environmental concern, and that any additional incentives would be duplicative. This code includes a risk based approach to strategic replacement and aims to benchmark current environmental performance and sets improvement targets and milestones.

5.92. We will however include forecast data reporting required as part of regulatory reporting for the RIIO-ED1 period.

Summary of our consultation proposals

5.93. We proposed that no additional intervention was necessary to incentivise mitigating actions or management of fluid filled cables.

5.94. In an effort to ensure completeness in reporting, we proposed enhanced forecast data should be included as part of regulatory reporting for RIIO-ED1 which would include details of planned replacement, where needed.

Summary of responses

5.95. There was agreement that the current approach is working well and additional forecast data to be included in regulatory reporting was welcomed.

Reasons for our decision

5.96. We engaged with both the DNOs and the Environment Agency during the price control process and are encouraged that the Operating Code between these parties continues to guide DNOs on their management of the impact of fluid filled cables on the environment.

Noise reduction

Our decision

5.97. We have decided to retain this reporting requirement as part of regulatory reporting along with enhanced reporting to explain the steps taken by the DNOs in cases where noise reduction activities have been conducted.

Summary of our consultation proposals

5.98. Our proposal outlined that the noise reduction reporting requirement did not appear to be particularly transparent. We proposed removing this reporting requirement because it did not appear meaningful.

Summary of responses

5.99. Most DNOs agreed with our suggestion to remove this reporting requirement. However, one DNO pointed out that the issue of this requirement not being meaningful or transparent would be better remedied through enhanced narrative to accompany any reported expenditure under noise reduction. This DNO also confirmed that noise reduction can incur a real cost where complaints about noise act as a primary driver for particular activities and associated expenditure by the DNO.

Reasons for our decision

5.100. On review, we agree that this work can represent a material cost to DNOs and therefore have decided to retain it in the reporting requirements. We agree that meaningfulness and transparency may be better served through an amendment to the reporting table and potentially the definition of this term, as necessary, rather than complete removal of the requirement. We consider that the removal of reporting on noise reduction activities would contradict our other proposals in this chapter for enhanced reporting requirements.

Environmental discretionary reward

Our decision

5.101. We have decided to develop a reputational environmental reporting requirement to address concerns around public accountability and integration of learning and performance. We will engage with DNOs and relevant stakeholders to develop this thinking further.

5.102. We have decided against including an environmental discretionary reward. We considered that our proposals for connections including of low carbon technologies (ie distributed generation), innovation and the use of smart grid solutions mean that a reward using criteria similar to those in RIIO-T1 would be highly duplicative. We consider that the current package of incentives and outputs provides a sufficient framework to adequately incentivise DNOs to integrate carbon and other environmental considerations within their day-to-day business.

Summary of our consultation proposals

5.103. In our consultation, we set out how we are designing RIIO-ED1 to encourage the DNOs to anticipate the impact of the low carbon future on their networks and the role that they will need to play. We questioned whether the DNOs need further incentives to manage their broad environmental impact.

5.104. We welcomed views on whether our planned package of incentives and outputs contained any gaps that would be best addressed through an environmental discretionary reward, which would be incorporated as an additional element of the proposed reward scheme for distribution losses reduction.

Summary of responses

5.105. The majority of respondents felt that there may be some merit in the introduction of such a reward scheme for environmental measure. However, apart from suggesting that such a reward scheme would drive behaviour and could be a powerful reputational incentive, for instance in the connection of renewables, respondents only indicated two potential gaps that this scheme might cover; meeting carbon reduction targets and waste management obligations.

5.106. There were also concerns raised regarding the public accountability and transparency of DNOs' progress and approach to meeting their environmental obligations. Some respondents advocated the merits of a balanced scorecard framework, as in RIIO-T1.

Reasons for our decision

5.107. We acknowledge concerns relating to public accountability and the integrated thinking DNOs should be demonstrating in leveraging performance and learning with respect to their environmental obligations. We consider this would be best addressed by a reporting requirement on DNOs' environmental performance.

5.108. We consider that the facilitation of low carbon technologies in connections, innovation and addressing of environmental impacts[29] forms a strong element of the current distribution price control, DPCR5. Discretionary reward schemes are of value where they seek to establish and encourage behaviour to be integrated into the business of a participant. We consider that DNOs have already been provided with clear signals regarding the establishment of appropriate behaviour in these areas and specifically in addressing the impact of a low carbon future through the design of DPCR5.

[29] Losses, undergrounding, business carbon footprint etc.

5.109. Our design of RIIO-ED1 maintains the emphasis on these elements, encouraging greater focus on innovation, integration of smart grids into business as usual, performance in the connections sector and enhanced reporting and monitoring. We consider there to be a strong emphasis on environmental incentives in RIIO-ED1 which compel companies to integrate these issues in their business plans. Companies would struggle to meet the minimum criteria for fast-tracking if this was not the case. Therefore, we see little reason in introducing an environmental discretionary reward.

5.110. Furthermore, waste management or meeting carbon reduction targets, whilst not explicitly addressed in the price control, are associated with appropriate external obligations for DNOs and we expect that the RIIO-ED1 emphasis on preparing for a low carbon future should complement and encourage behaviour that will improve performance under these obligations.

6. Customer satisfaction

Chapter Summary

This chapter outlines what we require DNOs to deliver in order to improve how they respond to the needs of their customers. We want DNOs to provide customers with a good quality service; we want DNOs to deal with complaints quickly and effectively; and we want DNOs to carry out meaningful engagement with a wide range of stakeholders. Our incentive framework is intended to drive improvements in DNO performance in each of these areas.

Our decision

6.1. We want to ensure that DNOs are focussed on providing a good service to customers. For many customers this service is limited to ensuring they receive a reliable supply of electricity. The long-term safety and reliability of the electricity distribution networks is core to the work of DNOs and this is reflected through a suite of measures outlined in Chapter 4. Other customers however, have (or require) a more significant interaction with the DNO and we have identified the need for separate incentives to apply to the service that they receive.

6.2. Our incentive framework is therefore intended to drive improvements to the service provided to customers that require a new connection, seek information from the network in the event of a supply interruption or have made a general enquiry. We also expect network companies to take the necessary steps to ensure that complaints are dealt with quickly and effectively. Finally, we want to ensure that the DNOs are sufficiently incentivised to engage with a wide range of stakeholders and use the outputs from this process to inform how they run their business.

6.3. We will therefore retain the Broad Measure of Customer Service (BMCS) that was established in DPCR5, with its three components of (i) a customer satisfaction survey (ii) a complaints metric and (iii) a reward based on an assessment of each DNO's stakeholder engagement activities.

6.4. We will increase the overall maximum revenue exposure applied to the BMCS from +/- 1 per cent in DPCR5 to +/- 1.5 per cent of base revenues in RIIO-ED1.[30] This is to ensure that DNOs are sufficiently incentivised to improve performance in customer-facing activities over a longer-term price control period. In particular, this will provide a stronger incentive to improve the service provided to connections customers. This will also strengthen the

[30] This will be set as a £m figure in the DNOs' licences, based on +/-86 basis points of RORE.

incentives on DNOs to ensure a broader coverage and engage with stakeholders, with a specific focus on their role in addressing consumer vulnerability.

6.5. The maximum financial exposure associated with the BMCS is slightly smaller than proposed in our September strategy consultation. This is due to an element of our proposals (a survey amongst major connection customers which was accompanied with a maximum penalty of -0.5 per cent of base revenues) being removed from the BMCS and replaced with a separate incentive mechanism (see Chapter 8 for details).

6.6. Table 6.1 below sets out the different elements of the BMCS and the level of financial exposure that will be associated with DNO performance.

Table 6.1: Broad Measure of Customer Service

BMCS Incentive		**Maximum reward/penalty (per cent of annual base revenue)**[31]
Customer satisfaction survey	Connections	+0.5/-0.5
	Interruptions	+0.3/-0.3
	General enquiries	+0.2/-0.2
Complaints metric		0/-0.5
Stakeholder engagement incentive		+0.5/0
Maximum penalty/reward exposure		**+1.5/-1.5**

6.7. DNO performance in both the customer satisfaction survey and the complaints metric will be measured against fixed targets. We will gather data on performance in DPCR5 and use this to set targets for RIIO-ED1. We provide more detail below on the various elements of the BMCS.

Customer satisfaction survey

6.8. We are retaining the three customer categories that are currently included in the customer satisfaction survey for DPCR5. The level of reward/penalty associated with each category is outlined in Table 6.1 above. These categories are as follows:

- connection customers
- customers experiencing an interruption
- customers making a general enquiry.

[31] As stated previously, this will be set as a £m figure, based on common basis points of RORE.

6.9. In calculating performance under the customer satisfaction survey, we will factor in the number of 'unsuccessful' calls from customers experiencing an interruption, eg calls terminated by the DNO or calls abandoned by the customer in the queue. For this category a DNO's overall performance score will therefore deteriorate the more calls it fails to answer. We will work with DNOs and other stakeholders to ensure that this mechanism is implemented consistently.

6.10. We will extend the reach of the customer satisfaction survey by including all customers making a general enquiry to the DNO where a service has been provided and/or a job has been completed, regardless of their chosen communication channel.

6.11. We will also extend the reach of the customer satisfaction survey by including customers who have experienced an interruption and received relevant information from the DNO via new communication channels.[32] We will work with stakeholders to specify the type of contact that will be included in the sample for the survey.

6.12. The survey that is conducted with connections customers will only include those that have required a 'minor' (lower voltage, metered demand) connection. Separate incentives will apply to the service provided to customers requiring a 'major' (higher voltage metered demand, unmetered, distributed generation) connection, but these will not be included in the BMCS. This reflects concerns raised about the viability and suitability of a survey, given the more complex nature of their relationship with DNOs and the relatively small number of these customers. More detail on our approach for connections customers is provided in Chapter 8.

Complaints metric

6.13. The complaints metric will consist of four components which are set out in Table 6.2 below. We also indicate the weighting that will apply to each separate component in calculating overall performance.

Table 6.2: Complaints metric

Indicator	Weighting
The percentage of total complaints outstanding after one day	10%
The percentage of total complaints outstanding after 31 days	30%
The percentage of total complaints that are repeat complaints	50%
The number of Energy Ombudsman (EO) decisions that go against the DNO as a percentage of the total complaints	10%

[32] At present only those customers experiencing an interruption that contact the DNO by telephone to request information are included in the survey sample.

6.14. These arrangements are broadly equivalent to those that apply to the existing complaints metric used in DPCR5. However, we have changed the methodology used to assess Energy Ombudsman (EO) decisions that go against the DNO; these will now be expressed as a percentage of total complaints (instead of a percentage of EO decisions). We have also reduced the weighting that is applied to this element of the incentive from 20 per cent to 10 per cent, with the remaining 10 per cent being added to component '(ii) the percentage of total complaints outstanding after 31 days'.

6.15. DNOs that perform at or above target levels will not be exposed to any financial penalty. Those that fail to achieve target levels of performance will face a penalty up to a maximum of -0.5 per cent of annual base revenues. In line with consultation responses, we will undertake further modelling to identify the level of performance at which the maximum penalty will apply.

Stakeholder engagement incentive

6.16. This incentive is intended to encourage DNOs to engage effectively with a wide range of stakeholders and use the outputs from this process to inform how they plan and run their business. In doing so, this should help enable the ongoing delivery of an efficient network that embraces wider social and environmental objectives.

6.17. We will increase the overall exposure of the stakeholder engagement incentive to +0.5 per cent of base revenue. In strengthening this incentive, we specifically want to encourage DNOs to maximise their role in addressing issues relating to consumer vulnerability. Our expectations of the role DNOs should play in addressing consumer vulnerability are outlined in Chapter 7.

Summary of our consultation proposals

6.18. In our September strategy consultation we proposed a range of outputs and incentives (based upon existing arrangements) to improve the service provided by DNOs and their approach to engaging with stakeholders.

6.19. We proposed to maintain the BMCS, which was introduced in DPCR5. To drive improvements in the overall quality of the customer experience, we proposed to increase the maximum penalty/reward exposure to +1.5/-2 per cent of annual base revenues.

Customer satisfaction survey

6.20. We did not propose any changes to the three customer categories. We proposed to increase the overall maximum revenue exposure applied to the BMCS customer satisfaction survey to +1/-1.5 per cent of base revenues. This increase would require DNOs to focus more specifically on providing a better service to customers seeking a connection. We proposed that a fixed target, as opposed to a rolling target, had merits.

6.21. We proposed to include in the sample of customers included in the survey those who had made a general enquiry regardless of the communication channel used. We also sought views on whether to include customers that have experienced an interruption and received information from the DNO through a broad range of communication channels.

6.22. We sought stakeholder views as to whether the number of unsuccessful calls made to a DNO should be factored into a DNO's overall performance.

6.23. In order to improve services for connections customers, we proposed to introduce a new survey specifically to canvas the views of customers requiring a major connection. This was proposed to be more qualitative in nature with a particular emphasis on the DNO's ability to provide information to their connections customers.

Complaints metric

6.24. We considered the DPCR5 BMCS complaints metric remained a useful method of ensuring DNOs manage complaints effectively and therefore proposed to maintain the maximum (penalty only) exposure of the incentive at -0.5 per cent of base revenue. However, we noted that as all DNOs are performing significantly better than the maximum penalty level, the size of penalty for companies that perform below the target is relatively small.

6.25. We therefore proposed to review the maximum penalty levels to ensure there is sufficient incentive on DNOs to improve their complaint handling performance. In addition, we proposed to either reduce the overall weighting applied to the EO element of the BMCS complaints metric score or to change the indicator to reflect the percentage of total complaints that are referred to the EO and found in favour of the complainant.

Stakeholder engagement incentive

6.26. We looked to increase the overall exposure of the incentive from +0.2 per cent to +0.5 per cent of base revenue. This was to incentivise DNOs to explore a range of issues with stakeholders and also to align with the maximum revenue exposure introduced for RIIO-GD1.

6.27. In addition, we proposed that the increased incentive would encourage DNOs to address key social issues (eg fuel poverty and consumer vulnerability) or undertake activities that lead to significant benefits for key groups of stakeholders.

Summary of responses

6.28. All DNOs supported the proposal to retain the BMCS and most agreed with increasing the maximum revenue exposure. However, a couple of DNOs thought that the incentive was disproportionately weighted towards connections customers, and noted the higher volume of customers that are affected by interruptions. A supplier stated that they agreed with the retention of the BMCS, but disagreed with the increase in the size of the incentive as they felt that the DNOs did not need more incentive to deliver the outputs required. Consumer groups and suppliers welcomed the proposals for BMCS, but expressed doubt as to whether it delivered value for money for all customers. They felt that most customers would have little interaction with the DNO and may therefore not benefit from any improvements in the aspects of service covered by the BMCS.

6.29. Several DNOs considered that we should fix targets for the whole of the RIIO-ED1 price control period. The DNOs argued that fixed targets would encourage them to share best practice and would also make it easier for them to build a business case for new investment in order to improve service. One DNO suggested that fixed targets may need to be reviewed during the period if there is a significant change in performance.

6.30. A supplier and consumer group proposed that rolling targets should be used to respond to changes in industry performance and that the penalty and rewards associated should not be asymmetric.

Customer satisfaction survey

6.31. The majority of DNOs and a consumer body felt that a wider range of customers who have received information about an interruption should be included in the sample for the survey. This would therefore include those who have received information through social media and other communication channels. This view was accompanied by the proviso that the DNO should be able to identify individually these customers and whether they have been affected by an interruption.

6.32. However, a couple of DNOs and a supplier expressed doubts about this approach. One DNO thought that alternative channels of communication constituted only a tiny proportion of customer interactions (compared to telephone contacts). They also felt that the type of communication via these media was too broad to meaningfully capture the provision and receipt of information relating to a specific incident. As these channels of communication have not been included in the data used for target setting they should not be included in the survey that determines performance.

6.33. The majority of DNOs felt that the number of unsuccessful calls should be included in the calculation of overall performance. However, in doing so they wanted to ensure there was no perverse incentive on a DNO to reduce the flow of calls. It was noted that DNOs may need to amend their telephony arrangements to ensure this is applied consistently. One DNO did not think unsuccessful calls should be included as they felt that past experience had led to problems with establishing (and auditing compliance with) common definitions. This DNO believed that customers would eventually get through to the DNO and that therefore the experience of those who do not is already captured.

6.34. The majority of respondents were supportive of splitting the connections component of the customer satisfaction survey into minor and major customers. However, several parties expressed concerns that the smaller number of major connection customers would make it challenging to develop a sufficiently robust sample size upon which to assess performance. It was noted that the difficulty of developing a robust methodology for major connection customers would be compounded by the impact of the Competition Test process.[33]

Complaints

6.35. DNOs agreed with the approach to maintain the current indicators for the complaints metric, and the majority agreed with the proposal to reduce the weighting given to EO complaints to 10 per cent. In addition, it was also felt by some DNO respondents that the EO element should reflect findings in favour of the customer as a percentage of the total number of complaints, rather than the existing measure of 'the percentage of EO decisions that find in favour of the complainant'.

6.36. A couple of DNOs felt that the approach to calculating the score at which the maximum penalty would be realised should be the same as for RIIO-GD1, ie 1.75 standard deviations from the mean, but that modelling should be undertaken to identify a new maximum penalty score.

Stakeholder engagement incentive

6.37. DNO respondents agreed with our proposal to increase the overall incentive for stakeholder engagement from +0.2 to +0.5 of base revenue. The DNOs felt that this increase would give a clear incentive for wider engagement. They would however like early sight of assessment criteria and guidance. A supplier felt that this additional incentive should deliver the necessary consumer engagement and customer experience required for the smart meter rollout. A trade organisation added that the incentive should encourage stakeholder engagement geared around the needs of the audience rather than the convenience of the DNO.

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[33] See Chapter 8 for more information.

Reasons for our decision

6.38. We will increase the overall maximum revenue exposure applied to the BMCS. We recognise that not all respondents were in favour of this increase, however we believe stronger incentives are required to ensure DNOs make the necessary improvements to their service (in particular to connections customers) and their approach to stakeholder engagement. Following the introduction of the BMCS in DPCR5 we have seen DNOs respond positively to BMCS incentive and make improvements to their service provision. We are confident therefore that this incentive mechanism is effective in changing DNO behaviour.

6.39. Whilst we agree that it may only be a minority of customers who interact with a DNO, the point at which this interaction occurs is invariably critical. For example, customers who are experiencing an interruption in supply or requiring a new connection. In these instances we believe it is essential that the DNO is incentivised to provide an appropriate level of service.

6.40. For reasons set out below, we do not propose to include major connections customers in the customer satisfaction survey. The incentive (-0.5 per cent of base revenues) that was associated with this element in our September strategy consultation has therefore been removed from the BMCS. This decision has reduced the overall range of this incentive (there is however a corresponding increase in the incentive value associated with connections outputs – see Chapter 8).

6.41. We agree that setting a fixed target for the period is an effective way of delivering improvements in service. We believe that this approach makes it easier for DNOs to justify additional investment where this will lead to service improvements. By setting a target score at the outset of the RIIO-ED1, we can be more confident that the allocation of financial rewards or penalties will accurately reflect the performance delivered (a 'relative' approach could result in DNOs receiving rewards for performance which, whilst better than other DNOs, is poor in comparison to other industries – and vice versa). The above principles apply for setting the target score for both the customer satisfaction survey and the complaints metric.

6.42. We aim to establish a target score at the outset that can be objectively assessed to represent a good level of performance, even when compared to other industries employing equivalent metrics. As part of this process we will consider whether there is requirement to ratchet up the score across RIIO-ED1.

Customer satisfaction survey

6.43. We want DNOs to communicate with their customers by using the medium that is most suited to the customer's needs and this may involve exploring new technologies. We want the survey arrangements that are in place to be able to accommodate these changes. We believe we will encourage this behaviour by expanding the scope of the customer survey to capture all interruption customers that have been proactively contacted by the DNO.

6.44. We note concerns raised at including a wider range of contacts within the survey. We believe however that these are largely addressed providing that each customer has meaningful contact with their DNO. In practice, for customers who have not contacted the DNO by telephone this would mean that:

- the customer would either have proactively opted into the information service provided (and that this could be linked to their unique Meter Point Administration Number) or
- customers must have had a direct communication with the DNO via a published channel (ie this would not include a customer who had been contacted via a blanket broadcast message or generic social media /internet message) and
- the DNO has the necessary contact details.

6.45. Additional filter questions may need to be attached to the customer satisfaction survey, to ascertain how and when the customer had contact with the DNO. We will develop and trial a revised approach that seeks to accommodate customer contacts that meet the relevant eligibility criteria.

6.46. Changes in the scope and methodology of the customer satisfaction survey may have implications on the scores received. We therefore consider that the inclusion of these proposed changes will be incorporated into the survey methodology prior to setting targets.

6.47. In line with consultation responses, we have decided that the number of unsuccessful calls should be included for the interruptions element of the incentive. We expect DNOs to take the necessary actions to ensure that customers requiring assistance do not experience difficulties in contacting them. We do not believe that a presumption that all customers will get through eventually is either accurate or acceptable. However, we will work with the DNOs to ensure that there is no perverse incentive to reduce call volumes and that there is consistency in the approach taken by each DNO.

6.48. We share concerns that have been expressed about achieving a robust sample size for a new survey for major customers and have therefore decided that an alternative approach is required. The Incentive for Connections Engagement (ICE) that is described in detail in Chapter 8 can encompass a broader range of performance measures than a single survey and can be tailored to the needs of different types of major connections customers.

Complaints

6.49. We recognise that measuring 'the percentage of EO decision that go against the DNO' potentially places too great a weight on a small number of cases (ie if the EO only makes one finding and it goes against the DNO, this represents 100 per cent failure against this element of the metric). As a result a DNO could face a penalty that may be far in excess of the value of the works in dispute and could therefore be perversely incentivised to avoid EO findings, regardless of their merits of their position. Therefore to reduce this risk, we propose to change the metric to 'the number of EO decisions that go against the DNO as a percentage of the total complaints'. Since the number of the cases referred to the EO is relatively low, the contribution to a DNO's composite metric score will be correspondingly reduced.

6.50. In our September strategy consultation, we proposed that either the overall weighting to the EO metric is reduced (to 10 per cent) *or* the indicator should change to reflect the percentage of total complaints that are referred to the EO and found in favour of the complainant.

6.51. However, after considering responses to the consultation, and also to bring the proposals in line with RIIO-GD1, we have decided to reduce the weighting of the EO element of the complaints metric *and* change the metric to reflect the percentage of EO decisions that go against the DNO as a percentage of total complaints received. We believe this is a fairer arrangement and reduces the risk of a DNO facing disproportionately large penalties for a small number of EO decisions.

6.52. We have placed the additional 10 per cent weighting (from the reduced EO component) on the percentage of complaints unresolved after 31 working days, as we believe that this is an area where DNOs have significant opportunity to improve their service and business processes. We have decided the incentive rate will be determined by dividing the total revenue exposure by the difference between the maximum penalty score and the industry target. This is in line with our approach for RIIO-GD1.

Stakeholder engagement incentive

6.53. Our aim for the stakeholder engagement element of the BMCS is to reward companies for high quality outcomes resulting from the stakeholder engagement process. In order to achieve the required results we will increase the maximum exposure of the incentive from +0.2 per cent to +0.5 per cent of base revenue.

6.54. Specifically, we intend for DNOs to use this increased incentive to ensure they maximise the role they can play in addressing issues associated with consumer vulnerability. For more information on this, please see Chapter 7.

7. Social obligations

Chapter Summary

In this chapter we set out the role we expect DNOs to play to help consumers in vulnerable situations. We describe the type of activities we expect DNOs to undertake and how these might be funded and rewarded.

Our decision

7.1. We believe that DNOs have an important role to play in helping consumers in vulnerable situations. We set out below the type of activities and behaviours they will need to undertake to fulfil this role. These should be considered alongside other measures we are taking to improve current arrangements. For instance, we are introducing arrangements to ensure vulnerable customers automatically receive any payments due under the guaranteed standards for supply interruptions.[34]

7.2. Our Consumer Vulnerability Strategy[35] and work programme will be published in spring 2013. It provides an overarching framework for how we will consider consumer vulnerability going forward. The overall objective is to take a more sophisticated approach to understanding vulnerability within the energy market. We want to encourage DNOs to maximise their role in understanding, identifying and dealing with consumers in vulnerable situations. We recognise that for DNOs to fulfil this role they will need to undertake a major cultural and behavioural shift.

7.3. DNO business plan submissions will need to demonstrate their strategy for realising this objective. In particular, they need to explain how they will:

- Improve the quality of information they have access to about vulnerable consumers and how it is used so that these consumers get the support and services they require.
- Engage with a wide range of stakeholders such as local authorities, devolved administrations, health providers, suppliers, other energy distributors (both gas and electricity), other utility providers and community groups. This engagement should consider how best to use the information they collectively hold on consumers in vulnerable situations.
- These activities should include the delivery of assistance to customers that are on their Priority Service Register (PSR). DNOs must explain the steps they will take to: publicise the benefits that are offered through the PSR, ensure that their PSR captures all of those that should be included and

[34] See Chapter 4 for further information.
[35] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=73&refer=Sustainability/SocAction

describe what assistance these customers may receive. This assistance may be provided directly by the DNO or by other agencies.[36]
- Utilise relationships and build partnerships with other stakeholders to identify and deliver solutions (both energy and non-energy) for affordable energy.
- Embed their strategy for addressing consumer vulnerability in their systems, processes and how they manage customer interactions.

7.4. We set out below more detail on how we see these strategies being implemented and the funding and incentive arrangements that will be in place for RIIO-ED1.

Strategy implementation

7.5. Through more effective use of consumer data and by establishing better partnerships with other stakeholders, DNOs will have a more mature understanding of the broader role they can play in assisting vulnerable customers. This could include, for example, enabling access to affordable energy.

7.6. This should not result in a DNO assuming responsibility for solving issues that extend beyond the scope of its business. This is about DNOs recognising the potential that is afforded by their function; specifically their ability to interact with consumers, their role in a community, the information they have access to and their scope to form partnerships with others.

7.7. The type of support a DNO provides may be in the form of direct assistance. Equally, however, there may be opportunities for a DNO to signpost the services provided by third parties or refer customers directly to other agencies.

7.8. In some instances these activities may reveal benefits for the broader base of network users. For instance, measures enabling more efficient use of energy for fuel poor households (through alternate heating technologies or in-home measures) might offset the need for wider network reinforcement.

7.9. Alternatively, a DNO may identify off-gas grid fuel poor customers and could help in the delivery of additional assistance. This could involve liaising with a gas network to enable a connection to the gas grid, or helping to identify alternative electric heat technologies or household efficiency improvements

[36] DNOs have a licence condition to maintain a PSR. This condition is in place to ensure DNOs identify and provide support to customers that may be especially vulnerable in the event of a supply interruption. As part of our Consumer Vulnerability Strategy, we are starting a comprehensive review of the PSR. However, the actions we expect DNOs to undertake will complement this review by 'raising the bar' on how they identify eligible customers and use the PSR to provide additional notification and support.

and linking in with government schemes/other forms of assistance that could support their delivery.

Framework for funding

7.10. Much of the above, including activity to help address fuel poverty, does not necessarily require additional expenditure. DNOs will be required however to outline and justify in their business plans their strategy, including the type of activities they plan to undertake to assist vulnerable customers, together with any associated costs and the outputs or benefits that will be delivered. We will then assess these as part of our decision on fast-tracking and proportionate treatment.

7.11. DNOs may also identify activities that require additional investment during the course of RIIO-ED1. DNOs already have strong load management incentives to undertake activities that avoid reinforcement costs. During RIIO-ED1 the efficiency incentive[37] provides an ongoing incentive for DNOs to seek out lower cost solutions and manage the cost of output delivery. This should ensure DNOs undertake schemes to work with customers to manage their electricity usage and offset the need for network reinforcement. Other, more innovative, schemes that may provide broader network benefits may be able to access funding to trial solutions through the Network Innovation Allowance (providing the scheme meets the relevant criteria).

Framework for reporting and reward

7.12. For DNOs to deliver a fully realised strategy that maximises their role in addressing consumer vulnerability they will need to undertake a significant change in their approach.

7.13. To ensure there is sufficient incentive for DNOs to make this change, the maximum level of reward available under the Stakeholder Engagement element of the Broad Measure of Customer Satisfaction will increase from +0.2 per cent of annual base revenues in DPCR5 to +0.5 per cent in RIIO-ED1. This increased incentive will enable us to assess and reward specifically the steps they are taking in response to the above challenges and the impact of their actions. To ensure we are clear on the broadening of scope of the Stakeholder Engagement incentive (and the specific emphasis we are placing on consumer vulnerability) we may alter the name of this incentive to reflect this shift in focus.

7.14. As part of the Stakeholder Engagement incentive, we will develop a mechanism for assessing the DNOs' use of data and customer insight to

[37] The efficiency incentive shares any over- or under-spend against the company's allowed revenues between the company and the customer.

understand and identify effective solutions for vulnerable consumers, as well as their ability to integrate this into core business activities. This assessment could take the form of a balanced scorecard, to inform the allocation of reward for DNO performance in each of these areas.

7.15. We expect DNOs to deliver a set of outcomes from these activities. A well performing company would be rewarded where it demonstrates how it had used its data to develop enhanced customer service, targeted support, and developed partnerships that helped deliver a solution for vulnerable customers. Where we see good practice, we will reward it and ensure it is highlighted to other network companies (both DNOs and GDNs), and stakeholders more widely.

Summary of consultation proposals

7.16. In our September strategy consultation we outlined the role DNOs play in addressing customer vulnerability, including fuel poverty. We noted that DNOs already have licence requirements in place to maintain the PSR. However, we set out that the effectiveness of the PSR, in enabling priority services to be provided to the right customers, depends on the quality of information it contains.

7.17. We proposed that DNOs use their business plan to describe how they will work in partnership with other stakeholders to share and use information on consumer vulnerability more strategically during RIIO-ED1.

7.18. To incentivise wider engagement we proposed to increase the Stakeholder Engagement incentive (within the Broad Measure of Customer Service) from +0.2 in DPCR5 to +0.5 per cent of base revenue in RIIO-ED1.

7.19. We invited responses to identify any potential activities or measurable outputs that DNOs may be best placed to deliver and whether specific funding should be made available for these identified activities.

Summary of responses

7.20. In general, respondents agreed that DNOs should focus on improving the information and assistance provided to customers on the PSR.

7.21. There was also broad support for DNOs to work with other agencies responsible for the health and well-being of residents to identify any additional issues, and increase awareness of the full range of support to which eligible households may be entitled.

7.22. Some non-DNO respondents felt that DNOs should, wherever possible, do more to enable access to affordable energy for off-gas and off-electricity grid customers. Some respondents also highlighted that DNOs could support the installation of measures to reduce heating costs for low-income households. It was highlighted that this approach might also enable a reduction in expenditure on network reinforcement. For example, if a DNO were to replace electrically heated tower blocks with a contribution towards a district heating network, this may reduce energy consumption and, in turn, the need for additional network capacity.

7.23. It was suggested that DNO assistance could be delivered in a number of ways (potentially involving liaising with a gas network to enable a connection to the gas grid, or helping to identify alternative electric heat technologies or energy efficiency improvements). One respondent highlighted that network companies could charge a lower cost to customers (reduced or zero Use of System charges) on the PSR, or redistribute 'surplus' funds from the gas fuel poor network extension scheme to enable electricity heating solutions for those off the gas grid.

7.24. One respondent noted that as DNOs provide a monopoly service, in many ways this makes them well placed to deliver against a range of social issues, not necessarily limited to those involving the distribution of electricity.

7.25. Although respondents were able to describe the type of activities DNOs might undertake, they were less able to propose tangible outputs that the DNOs should be responsible for delivering. One non-DNO respondent proposed that a DNO could be incentivised for the length of their cabled network that is shared with another utility (such as broadband). DNOs themselves did not propose any output measures.

7.26. The majority of respondents stated that a separate funding allowance would only be appropriate if the activity being funded could be clearly identified and the expenditure was supported by stakeholders.

7.27. In general, respondents agreed that the proposal to increase the reward available under the Stakeholder Engagement incentive should enable DNOs to undertake initiatives addressing social issues. However, a couple of respondents noted that it may not encourage investment in innovative approaches or encourage other DNOs to adopt best practice.

7.28. A number of DNO respondents and one consumer group felt that consideration should be given to allow funding for the delivery of projects that may benefit vulnerable customers but which have not been funded at the outset of RIIO-ED1 (similar to the innovation stimulus package). They stated however that access to this funding should only be allowed for specific activities and where strict criteria have been met.

Reasons for our decision

7.29. We do not believe that a specific social output that is entirely within the control of a DNO to deliver has been identified. However, we believe that our broader RIIO-ED1 package will encourage DNOs to play a major role in helping to address certain social issues. In developing and implementing strategies that fulfil this role, DNOs will undertake many of the activities identified by respondents, or at least explore their potential for doing so.

7.30. Additionally, in response to our consultation some further, more radical, suggestions were made. These included offering zero use of system charges for fuel poor households and redistributing funding from the gas fuel poor network extension scheme to enable electricity heating solutions for those off the gas grid. Whilst both suggestions are of interest, we feel neither is appropriate for the RIIO-ED1 price control framework. The first proposal would require an increase in DUoS charges for other customers, thereby potentially placing more customers into fuel poverty. This proposal would also require DNOs to maintain a comprehensive register of all households that are in fuel poverty, requiring access to information that is not within their control to obtain. The second suggestion raises issues under our statutory duties.

7.31. Much of the above, including activity to help address fuel poverty, does not necessarily require additional expenditure and no specific activities requiring direct funding were identified in consultation responses. Given this, we do not believe there is sufficient justification to establish a separate funding stream to enable the delivery of these and other, as yet unspecified, activities.

8. Connections

Chapter Summary

This chapter outlines our decision on the connections incentives and arrangements that will be applied during RIIO-ED1. These incentives and arrangements are designed to promote a significant improvement in the connection service that customers receive.

Introduction

8.1. Under the Electricity Act 1989, DNOs are obliged to offer a connection to any customer that wishes to connect to the network. Customers seeking a new connection rely upon the DNO to provide them with an efficient, high quality service. When customers are not connected in the timescales they require this can result in significant adverse consequences, both to individual customers and to society more generally; new businesses are unable to open their doors, new housing is not made available and low carbon generators are unable to export to the market.

8.2. Despite introducing a range of incentives to improve performance in DPCR5, we remain concerned that the experience of connecting to the distribution network continues to fall below the expectations of many customers.

8.3. DNOs need to deliver a service that meets the requirements for all connections customers. The type of services a customer requires may depend on the type (or size) of connection they seek and this in turn may impact upon how performance should be measured and incentivised. For connections at the lower voltages (minor connections) the connections process can be reasonably straightforward. We have put in place output measures and associated incentives to ensure that these customers get a good level of service and are connected in quicker timescales than they currently experience.

8.4. For connections at higher voltages and generation/unmetered connections – major connections – their requirements are often more complex and we have taken this into account in how we have designed the incentive framework for these customers.

8.5. We also recognise that customers at the higher voltages may be able to choose between using a DNO or an alternative connections provider. In parallel with the development of the RIIO-ED1 incentive framework, we are assessing the level of competition in various segments of the connections market (the 'Competition Test'). Where we see evidence of effective competition we will not apply regulatory incentives on the connection services provided by the DNO (other incentives such as the stakeholder engagement incentive and the complaints metric that form components of the BMCS will continue to operate in these market segments). Appendix 2 provides detail on the impact of the Competition Test on our RIIO-ED1 proposals.

Our decision

8.6. We have decided upon a package of incentives to promote improvements in the connections service provided for RIIO-ED1. This package includes:

- a customer satisfaction survey (for minor connections customers)
- a Time to Connect incentive (for minor connections customers)
- an Incentive on Connections Engagement (ICE) (for major connections customers).

8.7. We have also reviewed existing licence conditions that relate to connections services, in particular those concerning the connections guaranteed standards of performance and those requiring DNOs to provide information to prospective connections customers.[38] We have decided to retain the following licence conditions because we consider that they continue to benefit customers:

- Connections Guaranteed Standards of Performance
- publication of a Long Term Development Statement
- publication of a Distributed Generation (DG) Connections Guide.

8.8. We will however remove the requirement for DNOs to publish an Information Strategy because we consider that this is not delivering the right outcome for customers. Instead we have incentivised the provision of good quality information through the ICE mechanism.

8.9. For RIIO-ED1 we are increasing the overall strength of the incentives on DNOs to focus their attention on their connections activities. Our decision on the financial values of the various incentives that will apply to connection activities is summarised in Table 8.1 below:

[38] Electricity Distribution Standard Licence Condition 25 'Long Term Development Statement' and Standard Licence Condition 25A 'Distributed Generation: Connections Guide and Information Strategy'.

Table 8.1 Maximum revenue exposure for RIIO-ED1[39]

Scope	Incentive/ Measure	Maximum reward exposure (per cent of base revenue)	Maximum penalty exposure (per cent of base revenue)
All connections customers	Guaranteed Standards of Performance (GSOP) (minimum service level)	None	0/As per GSOP payment value
Minor connections customers	Customer satisfaction survey	+0.5	-0.5
	Time to Connect incentive	+0.4	0
Major connections customers	Incentive on Connection Engagement (ICE)	None	Up to -0.9
	Total Penalties/Rewards	+0.9	-0.5 to -1.4

Customer satisfaction survey (for minor connections customers)

8.10. The BMCS was introduced during DPCR5. Under the BMCS a customer satisfaction survey is conducted with customers who have experienced an interruption, made a general enquiry or required a connection. The survey measures the extent to which customers are satisfied with the service they receive. Financial penalties and rewards are linked to performance (as outlined in Table 8.1).

8.11. We will strengthen the incentives associated with the connections component of the customer satisfaction survey in order to encourage further improvements to the service. The survey sample will be drawn from minor connections customers who have received either a quotation or a completed connection.

8.12. The RIIO-ED1 customer satisfaction survey target will be based on industry performance in DPCR5. We will consult on the approach we will use to calculate the target and will set the target values prior to the start of RIIO-ED1.

8.13. We have decided to increase the financial exposure of the connection component of the customer satisfaction survey from +0.32/-0.2 to +/- 0.5 per cent of base revenue per licensee.

8.14. For more information on the BMCS please refer to Chapter 6.

[39] This will be set as a £m figure in the DNOs' licences, based on +23 and -52 basis points of RORE.

Time to Connect incentive (for minor connections customers)

8.15. This new incentive will measure the time taken from initial application received to the issue of a quotation and the time taken from quotation acceptance to connection completion. The incentive will capture minor connections customers. No exemptions will apply.

8.16. The Time to Connect incentive targets will be based on performance data captured in DPCR5. We will set the target values in advance of RIIO-ED1 and we have decided that they will decrease across the period (so that quotes will be issued and connections will be completed in increasingly shorter timescales for DNOs to be eligible for a reward). We will consult upon the approach used to determine the target and subsequent target values, prior to the start of RIIO-ED1.

8.17. The incentive will apply on a reward only basis. The maximum reward is 0.4 per cent of base revenue per annum, per distribution licensee.

Incentive on Connections Engagement (ICE) (for major connections customers)

8.18. We have decided to introduce the ICE to focus DNOs on understanding and meeting the needs of major connections customers.

8.19. As part of their well-justified business plans, we expect DNOs to set out their approach for meeting the requirements of these customers during RIIO-ED1. This will give us, and the wider community of connections customers, exposure to each DNO's high-level strategy for engagement and delivery.

8.20. Under the ICE, each DNO will be required to submit evidence of how they have identified, engaged with and responded to the needs of their customers. We will assess their submissions against a set of minimum requirements. The minimum requirements are likely to require each DNO to make a submission demonstrating how they have engaged with a broad range of customers, established relevant performance indicators and developed a forward-looking work plan of actions to improve performance (with associated delivery dates). DNOs will be required to make their submissions on a periodic basis (potentially on a biennial basis).[40] Subsequent submissions should demonstrate performance against their relevant performance indicators and progress against their work plan of actions.

8.21. Separate submissions will be required for different market segments; each representing a different type of customer (eg metered demand, DG, and

[40] Each DNO's initial workplan will be published before the start of RIIO-ED1.

unmetered). The DNO will incur a penalty if we consider that they have not satisfied minimum requirements for that market segment.

8.22. Alongside this assessment approach, we will continue to engage with stakeholders to identify key issues and gather feedback on DNO performance throughout RIIO-ED1. Specific focus will be placed on DNOs that are failing to deliver against commitments made in their work plan or achieve associated performance indicators. We will use this information to inform our assessment of the DNOs' submissions and whether to apply additional scrutiny to specific DNOs/market segments.

8.23. We will work with stakeholders to specify minimum requirements and the ICE assessment process prior to the start of RIIO-ED1.

8.24. The ICE is a penalty only incentive. The maximum penalty under the incentive will be 0.9 per cent of base revenue, per annum, per licensee. However, the maximum penalty that can be applied to a DNO will be proportionate to the market segments that have passed the Competition Test (ie if a DNO has not passed the Test for any market segments, then they will be exposed to penalties of 0.9 per cent of base revenue per annum. A DNO that has passed all market segments will face no penalty). We will consult on the approach used to scale the size of penalty (eg relative to the number or value of market segments that have not passed the Competition Test) prior to the start of RIIO-ED1.

8.25. The ICE will continue to operate even in those market segments where there is effective competition. However, in these instances, it will only capture the DNOs' provision of non-contestable[41] services and there will be no financial incentive attached.

Connections related licence conditions

Connections Guaranteed Standards of Performance (GSOPs)

8.26. The Connections GSOP[42] will remain in place for all connection customers during RIIO-ED1 (including voluntary payments for DG customers not covered by regulatory framework).

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[41] Much of the work involved in providing a connection can be undertaken by either the DNO or a competitive alternative (an Independent Connections Provider or/and Independent Distribution Network Operator) and is referred to a 'contestable' activity. At present other work, such as determining the point of connection to the DNO network, can only be undertaken by the DNO and is referred to as 'non-contestable'.
[42] The Connections GSOPs specify minimum standards of performance that we expect from each of the DNOs. If DNO fails to meet this standard of performance then they must make a compensatory payment to the customer affected.

8.27. All electricity distribution GSOP payment values, including the Connections GSOPs, will be updated to reflect inflation. We will inflate the existing standard payments by the forecast inflation amount to 2018-19. Additionally, payment levels will be rounded to the nearest £5; this will provide a simpler outline for both customers and DNOs.

8.28. The guaranteed standard payments for DPCR5 and the proposed payment level for RIIO-ED1 (as described above) are set out in Appendix 3.

Long Term Development Statement (LTDS), DG Connections Guide, Information Strategy

8.29. We have decided to retain licence obligations for DNOs to produce a LTDS per licensee area and a DG Connections Guide because we consider that they are useful to consumers. We have decided to remove the obligation on the DNOs to produce a DG Information Strategy because we do not consider that it is delivering the desired outcomes.

Treatment of customer contributions

8.30. At the end of RIIO-ED1 we intend to true up the difference between the value of relevant expenditure forecast to be funded by connection customers and the actual amount that is contributed. This true up would be carried out across the load-related expenditure as a whole, rather than just the connection cost categories.

Summary of consultation proposals and responses

8.31. In our September strategy consultation we consulted on proposals to improve connections services. We proposed to build upon DPCR5 connection arrangements and strengthen the financial incentive on DNOs to improve their connection services.

8.32. We noted that different types of customers may have different concerns, but we put forward proposals that did not differentiate between demand and generation connections.

8.33. We highlighted the potential impact of the Competition Test on our proposals. We sought wider views on how the presence of effective competition should affect our proposals.

Developments since our September strategy consultation

8.34. In parallel with the RIIO-ED1 price control process we have also held a number of DG Forum events to discuss the issues affecting DG customers trying to connect to the network. Our RIIO-ED1 proposals were discussed at each event. The feedback we received, together with the actions arising from these sessions, has informed our revised approach for all major connections customers.

Customer satisfaction survey

8.35. In the September strategy consultation we provided an overview of our proposed changes to the customer satisfaction survey for connection customers (as part of the BMCS). To ensure appropriate focus is placed on different types of connection customers we proposed separating the survey between minor and major connections customers. We invited views on how the survey could operate for major connections.

8.36. We questioned how the impact of the Competition Test should influence our proposals and sought views on whether additional incentives were required to improve the provision of non-contestable services by the DNOs.

8.37. The majority of respondents were supportive of splitting the connections component of the customer satisfaction survey into minor and major customers. However, several parties had concerns about developing a statistically robust methodology for sampling major connections customers in different market segments, given the small number of these customers.

8.38. One supplier disagreed with the increase to maximum reward/penalty exposure of the customer satisfaction survey as they felt that this would not guarantee corresponding expenditure from the DNOs. Consumer and trade associations welcomed the proposals, but expressed doubt as to whether it delivered value for money. One DNO was concerned that the proposed value of the financial incentives was disproportionate to the size of the connections market value.

8.39. Respondents agreed that effective competition should ensure that customers receive good customer service and, where this is the case, it may not be appropriate to apply additional incentives.

8.40. Stakeholders had mixed views on whether additional incentives were needed to improve performance in the delivery of non-contestable work. Some considered that there were already safeguards and incentives to ensure that DNOs deliver a good quality of service for these customers (eg Standard Licence Condition 15). Others considered that additional incentives were needed to improve customer service.

8.41. Further comments on the design of the customer satisfaction survey – and our response to them – are outlined in more detail in Chapter 6.

Time to Connect incentive

8.42. We proposed to introduce a new Time to Connect incentive to shorten the end-to-end process of connecting to the network. We proposed that the incentive would measure the:

- average time to produce a quote
- average time taken from quotation acceptance to completion of works.

8.43. We invited further views on the scope of the incentive, how to set the targets and the financial value of the incentive. We proposed tightening the target over the period in order to maintain a continuous focus on seeking improvements.

8.44. Stakeholders were generally supportive of introducing a Time to Connect incentive for minor connection customers. Some DNOs and larger connection customers considered that the Time to Connect incentive may not deliver improvements in the most critical areas of the service for major connection customers. For major connection customers, respondents were also concerned about using a potentially small sample size to set targets and monitor performance, as well as the impact of a small number of jobs with exceptionally long (five+ years) lead times.

8.45. DNOs were generally supportive of splitting the Time to Connect incentive into (i) the time to quote and (ii) the time from quote acceptance to connection completion. Some DNOs considered that exemptions should be applied for delays that are outside of the DNO’s control.

8.46. The DNOs were generally supportive of fixing individual targets for each DNO, based on their historic performance during DPCR5. They considered that this would take into account the different factors that affect performance in each DNO region.

Connections related licence conditions

8.47. The GSOPs set out the minimum timescales for delivering specified connections activities. We proposed retaining the Connections GSOPs for RIIO-ED1 and asked for views on whether we should increase payments to reflect inflation.

8.48. We considered that DNOs may be able to provide more information to connections customers earlier in the connections process that would allow them to make a more informed connection application. We proposed retaining the obligation on DNOs to produce LTDSs and a DG Connection Guide. We sought views on removing the obligation for DNOs to produce a DG Information Strategy.

8.49. We noted that improvements are being to information provision across the industry, but we invited views on whether an additional incentive was needed to drive further improvements. We suggested that the customer satisfaction survey might provide an appropriate vehicle to incentivise this behaviour.

8.50. Several respondents to our consultation highlighted the importance of the Connection GSOPs to customers.

8.51. All respondents considered that DNOs should retain a requirement to produce a LTDS and DG Connections Guide. The majority of respondents were comfortable with removing the obligation on DNOs to produce a DG Information Strategy and recognised that the existing requirements did not necessarily result in DNOs producing information that customers find useful.

8.52. There was a mixed response from stakeholders about whether additional incentives were necessary in this area. Some respondents considered that more incentives were required and suggested placing a greater weight on certain customer satisfaction survey questions. Other parties considered that there were already sufficient incentives on the DNOs to produce information to connection customers (eg BMCS, cost saving of dealing with reduced volumes of connection applications).

Treatment of customer contributions

8.53. We noted that our current treatment of customer contributions (ie costs recovered from connecting customers via connection charges) for 'high cost, low volume' connections may disincentivise the DNOs from undertaking strategic investment. To resolve this issue we proposed to adjust the DNOs' baseline allowance and recorded spend to take into account actual customer contributions. We asked stakeholders whether they agreed with our proposed approach. Respondents were broadly supportive of our proposals.

Reasons for our decision

Customer satisfaction survey

8.54. Based on responses to our consultation we have decided to retain the customer satisfaction survey for minor connections customers.

8.55. Ongoing feedback has highlighted the need to improve the DNOs' connections services and revealed that some customers do not receive the level of service they expect from the DNO. To ensure that DNOs place greater focus on responding to the changing needs of connections customers over RIIO-ED1, we have decided to increase the financial exposure on the connections element of the customer satisfaction survey to +/-0.5 per cent of base revenue, per distribution licence, per annum.

8.56. We share stakeholder concerns about achieving a robust sample size for major customers and therefore we have decided that the customer satisfaction survey will only capture minor connection customers.[43]

Time to Connect incentive

8.57. Responses to our consultation suggested that minor connections customers would benefit most from shorter end-to-end connection timescales and highlighted concerns over the application of this incentive for major connections. We have therefore decided that the Time to Connect incentive will only apply to minor connections customers. We consider that the ICE will incentivise DNOs to complete major connections in a timely manner, in accordance with customer requirements.

8.58. The Time to Connect incentive will measure the time from initial application received to the issue of a quotation and from quotation acceptance to connection completion. This will incentivise DNOs to reduce timescales for the elements of the connection process that are in the DNO's control. We have decided to start measuring from the date of initial application (as opposed to the date on which the application was accepted by the DNO) to ensure that DNOs are incentivised to help customers identify the minimum information required to progress their application, prior to its submission.

8.59. To ensure that DNOs improve service throughout RIIO-ED1, the target value will decrease across the period (ie connections will need to be completed in increasingly shorter timescales).

8.60. For the purposes of simplicity, we have decided that no exemptions will be applied to this incentive. We recognise that there will be a proportion of customers that require particularly long timescales for connections; however we believe that these are likely to be equally present in the base data used to set targets.

8.61. We consider that a potential maximum reward of 0.4 per cent of base revenue, per distribution licence, per annum is appropriate, taking into account the total value of the minor connection works completed. We consider that achieving a connection in a timely manner is likely to remain a key issue throughout the RIIO-ED1 period. We have set the value of this incentive at a lower level than the incentive applied to the customer satisfaction survey, to ensure that a DNO's main priority is satisfying customers. This approach

[43] For more information on the customer satisfaction survey (eg target setting) please refer to Chapter 6.

should avoid any perverse incentives on DNOs to rush through the connections process at the expense of customer requirements.

Incentive on Connections Engagement (ICE)

8.62. Based on the feedback we received to our consultation, we revised our proposals for major connections. As a result we have introduced the ICE.

8.63. The ICE is intended to replicate the type of activities we expect DNOs to undertake in market segments that are subject to effective competition. For example, we expect a DNO seeking to win work from competitors should take steps to understand the needs of its customers, make improvements to their service where required and assure itself that these changes have delivered benefits to customers. We want DNOs to demonstrate the same behaviours for all customers. This approach allows service propositions and performance measures to be tailored to customer needs and evolve across the RIIO-ED1 period.

8.64. By requiring DNOs to make submissions under the ICE for non-contestable services, we will incentivise DNOs to engage with customers and improve their service, albeit with no financial penalty attached.

8.65. The size of the incentive (a penalty of up to 0.9 per cent of base revenue, per annum, per licensee) is equal to the size of the penalty that we proposed for the components of the Time to Connect incentive and the customer satisfaction survey that related to major connections customers in our September strategy consultation. The size of the penalty will be adjusted downwards for each market segment that passes the Competition Test.

8.66. In setting the size of the incentive, we have taken into account the total market value of these relevant market segments (including both contestable and non-contestable work). We note that the DNOs forecasted the value of their sole use funded demand connections to be over £1.7bn for DPCR5 (in addition to the DNOs' generation and unmetered connection work). We also consider that the value of an efficient connections service to customers often far exceeds the cost of work involved. We believe that this aspect of DNO activity is in particular need of improvement and that the incentive we attach must be of sufficient size to deliver the necessary changes.

Connections related licence conditions

8.67. We consider that the GSOPs protect customers from receiving poor levels of service and the DNO is the connection provider of last resort for all market segments. We have therefore decided that they will remain in place for all market segments in RIIO-ED1. To remain consistent with the approach used for the GSOPs that relate to the reliability of the network, we have used inflation forecasts to set the connection GSOP payment levels for RIIO-ED1.

8.68. Based on the responses to our consultation, we have decided to retain the DNOs' licence obligation to produce LTDSs and the DG Connections Guide during RIIO-ED1.

8.69. We consider that the DG Information Strategy arrangement is not delivering the desired information to DG customers. We have therefore decided to remove the obligation to produce a DG Information Strategy.

8.70. We note that several DNOs are already employing innovative methods to improve information provision. Based on the responses to our consultation, we consider that the RIIO-ED1 framework will provide sufficient incentive on DNOs to publish more information to connection customers at an earlier stage in the connections process (eg ICE, BMCS). We therefore consider it unnecessary to introduce a new incentive focussed solely on information provision.

Treatment of customer contributions

8.71. We will true up the difference between the value of relevant expenditure forecast to be funded by connection customers and the actual amount that is contributed. This true up will be carried out across the load-related expenditure as a whole, rather than just the connection cost categories. Stakeholders were broadly supportive of this approach and it should ensure that, from an allowed revenue perspective, DNOs are neutral to whether a specific level of reinforcement is carried out as part of a connections project or fully funded by the DNO.

9. Efficiency incentives and IQI

Chapter Summary

This chapter sets out our decision on efficiency incentives and the IQI for RIIO-ED1 and how these will apply for fast-tracked and non-fast-tracked DNOs.

Efficiency incentive rate

9.1. The RIIO framework is designed to ensure that DNOs face strong financial incentives to deliver outputs at an efficient cost, using approaches that provide better value for money for existing and future customers. In particular, in line with our September consultation document:

- We will determine a fixed and symmetric efficiency incentive rate for each DNO. This will give companies a clear and strong financial stake in managing, and where possible reducing, the costs of delivering outputs.
- We will not make retrospective adjustments to revenue in the event that costs turn out to be different to what was assumed in the price control itself, save through the application of the efficiency incentive rate and uncertainty mechanisms. We will only consider using ex post adjustments if outputs are not delivered or a DNO has manifestly wasted money.

9.2. We will set an efficiency incentive rate for each DNO for the duration of the price control period. This rate will apply regardless of whether the DNO has spent more or less than envisaged. The same efficiency incentive rate will apply to operating expenditure and capital expenditure. This will reduce the risk that decisions may be distorted in favour of capital expenditure solutions.

9.3. We set out the potential range of the efficiency incentive rate, and how we will assess it for each DNO, in the Information Quality Incentive (IQI) section later in this chapter.

Implementation of the efficiency incentive rate

9.4. In line with RIIO-T1 and GD1, we will apply the efficiency incentive through annual revenue adjustments during the price control period. This will form part of the annual iteration process for determining allowed revenues (as explained further in 'Supplementary annex – Financial issues'). Any revenue adjustment arising from the efficiency incentive will be made two years after the relevant expenditure is incurred. The time delay allows the DNOs to report their actual expenditure data and enables revenue adjustments to be calculated in good time, in line with our stated intentions on volatility of charges, to enable notification to network users of changes in DUoS charges.

9.5. The level of the efficiency incentive rate will determine the extent to which totex is adjusted in light of a given over-spend or under-spend. The higher the efficiency incentive rate, the more of any over-spend would be borne by the company and the more of any under spend would be retained by them. The 'Supplementary annex – Financial issues' sets out our annual iteration process for determining allowed revenues during RIIO-ED1.

Interaction with uncertainty mechanisms

9.6. The Supplementary annex - Uncertainty mechanisms' sets out our approach to managing uncertainty for RIIO-ED1 and the areas we believe require uncertainty mechanisms. In general, we would expect to set the uncertainty mechanisms for RIIO-ED1 such that any qualifying expenditure would be subject to the efficiency incentive rate. For example for a company with a threshold set at £10m, and an efficiency incentive rate of 50 per cent, then only where they have spent £20m would they be deemed to have met the re-opener threshold. Expenditure below the re-opener threshold, or in unanticipated areas not subject to a re-opener, would be subject to the efficiency incentive rate. The 'Supplementary annex – Uncertainty mechanisms' sets out how the efficiency incentive rate will interact with each uncertainty mechanism.

Information quality incentive (IQI)

Our decision

9.7. The IQI is designed to incentivise the network companies to provide accurate cost forecasts in their business plans and drive efficient expenditure. We will continue to use it in RIIO-ED1. The scope of the IQI will include costs and, where applicable, volumes associated with capital expenditure, network operating costs, closely associated indirect costs, business support costs and non-operational capital expenditure.[44]

9.8. We will include Real Price Effects (RPEs) in the costs that form part of the IQI assessment as there are close interactions with other types of costs and this is more consistent with a totex approach. This provides a strong incentive for DNOs to submit robust forecasts for RPEs.

9.9. A few small cost categories, such as traffic management costs (excluding administration costs) and guaranteed standards of performance, will be excluded from the application of the efficiency incentive rate and continue to attract a 100 per cent incentive rate. This is in order not to alter the marginal

[44] Indirect costs are broken into two categories: business support and closely associated indirect costs. Closely associated indirect costs include network policy (including research and development), network design and engineering, engineering management and clerical, wayleaves administration, control centre, system mapping and health and safety functions.

penalty rate as set by the Department for Transport in respect of traffic management and Ofgem in respect of guaranteed standards of performance payments.

Fast-track

9.10. Our approach is in line with RIIO-T1 and GD1: to provide a fast-tracked company upfront additional revenue of 2.5 per cent of totex (in lieu of the IQI settlement). Our approach for RIIO-ED1 is that each DNO that achieves fast-tracking is provided with the same upfront additional revenue of 2.5 per cent of totex. They will also receive an efficiency incentive rate of 70 per cent.

9.11. If a fast-tracked DNO would have been better off in the IQI matrix that is subsequently used for non-fast-tracked DNOs, then we will true-up the difference for that company. We will not claw back the 2.5 per cent if the fast-tracked DNO is below this level in the IQI matrix.

9.12. There will not be a published IQI matrix as part of the fast-track decision.

Non-fast-track

9.13. For a DNO that is not fast-tracked, we will produce our own view of its expenditure requirements (drawing on the DNO's business plans and our own benchmarking and cost assessment tools). We will set the IQI matrix based on the final submissions from all 14 DNOs.

9.14. We will calibrate the IQI so that a DNO which submits an expenditure forecast for RIIO-ED1 that matches our assessment of that DNO's efficient expenditure will be able to achieve a return equal to our estimate of its cost of capital, if it were then to spend, over the price control period, the amount it had forecast (leaving aside the impact of other incentive schemes on the company's returns). As set out in the 'Supplementary annex – Tools for cost assessment' our assessment will be based on upper quartile benchmarking of totex.

9.15. This means that DNOs that submit expenditure forecasts that are higher than our assessment of their efficient expenditure requirements would earn returns lower than our estimate of their cost of capital unless they were able to deliver outputs at lower costs than our assessment or to earn financial rewards through other incentive schemes. Our estimate of DNOs' efficient expenditure requirements will be reasonable and based on a range of information. We have set out how we intend to assess the DNOs' costs in the 'Supplementary Annex – Tools for cost assessment'.

9.16. The efficiency incentive rate for a specific DNO will depend on the ratio between its expenditure forecast and our assessment of its expenditure requirements as well as the parameters used to calibrate the IQI. Whilst this means that there will be differences in the DNOs' efficiency incentive rates depending on the robustness of their forecasts, we can operate the IQI in a way that allows us to set the broad range of efficiency incentive rates upfront.

9.17. Our intended efficiency incentive rate range for RIIO-ED1 is 45-65 per cent, with a higher rate of 70 per cent for fast-track DNOs.

9.18. We will set out the IQI matrix as part of our Draft Determinations for the non-fast-track companies, which we intend to publish in July 2014.

Treatment of groups

9.19. Where there is more than one DNO within a single ownership group, we will set a single efficiency rate for the group. This rate will be calculated by assessing the sum of all expenditure forecasts of DNOs within a single ownership group. This is the same approach that we used for the current price control, DPCR5.

9.20. Where not all DNOs within a group are fast-tracked, we will set out the methodology for equalising the efficiency incentive rates in our July 2014 Draft Determinations. This is likely to be done based on the proportion of totex allowances for each DNO within the ownership group. For example, where DNO A has a proposed totex allowance of £750m and DNO B £250m, with proposed efficiency incentive rates of 70 per cent and 50 per cent respectively, then the equalised rate across the group would be 65 per cent.

Volume and output adjustments

9.21. We intend to include both cost and volume differences in our IQI assessment. Where a DNO opts to include additional outputs we will strip these out before compiling the IQI matrix. DNOs will need to clearly identify any costs associated with such outputs. Where a DNO opts to include additional volumes over and above those we believe are required, and fails to justify them, then we will include such differences in the calculation of their IQI ratio, i.e. a company that over-forecasts its required volumes will be penalised via the operation of the IQI matrix. It is our intention that such volumes will feed through into the DNO's relative position in the matrix. We believe this sends a strong signal to DNOs to submit robust forecasts of both volumes and costs for RIIO-ED1. Where a DNO justifies extra volumes we will take these into account in our view.

9.22. Where an area is covered by a volume driver, eg for smart meter roll-out costs, then we will apply a consistent volume assumption for both the company forecast and the Ofgem view.

Summary of consultation proposals

9.23. In our 'September strategy consultation', we stated that we intended to continue both the IQI and the efficiency incentive.

9.24. However, we proposed to change the start-to-earn point in the IQI matrix compared with previous price control reviews. We proposed that where a DNO's forecast expenditure was equal to our upper quartile assessment of its efficient expenditure requirements, the DNO would achieve a return equal to our estimate of its cost of capital if it delivered its outputs in line with its allowances.

9.25. We proposed to reduce complexity and boundary issues compared with DPCR5 and to bring the bulk of costs within the scope of a single efficiency incentive rate. As part of this approach we proposed to increase the strength of efficiency incentives for RIIO-ED1. We set out an indicative IQI matrix showing incentive rates from 50-70 per cent if DNO forecasts were between 90-130 per cent of our baseline.

9.26. We also consulted on rewards for fast-tracking and how we proposed to equalise the efficiency incentive rate across DNOs within the same group, where at least one DNO in the group was fast-tracked and the other(s) were not.

Summary of consultation responses

9.27. Responses to the consultation questions in this area suggested that the efficiency incentive rate should cover everything except for RPEs. In addition, there was agreement that the range of the efficiency incentive rate should be expanded to create a higher incentive to investment.

9.28. All respondents gave different views on the approach to the IQI. For calibrating the IQI it was suggested that either the approach should be consistent with RIIO-T1 and GD1 (ie providing expenditure estimates which match Ofgem's estimates would result in a financial reward), or the IQI should be aligned with mean rather than upper quartile benchmarking.

9.29. It was also suggested that RPEs should be excluded from the IQI assessment for RIIO-ED1, since they would be more appropriately dealt with via an uncertainty mechanism.

9.30. Several respondents referred to issues that may arise from the proposed IQI matrix, predominantly regarding the reward for fast-tracked or slow-tracked DNOs. The respondents suggested that fast-tracked companies should be rewarded differently from slow-tracked.

9.31. There was, however, no common agreement on a reward for fast-tracked companies. Suggestions included the use of the proposed IQI matrix, financial incentives (anywhere between two and five per cent), and an incentive rate at the top of the range plus an additional reward.

9.32. For slow-tracked companies, it was suggested that several IQI matrices could be introduced. One matrix would cover those companies that Ofgem had limited concerns over specific elements of the business plans, with another matrix for those companies that are subject to "other proportionate treatment".

9.33. Most respondents agreed with our proposal to assess the sum of all expenditure forecasts of DNOs within a single ownership group. They noted that if treated as a single group, the efficiency rate of a fast-tracked company would not be known until the review of the slow-tracked company is completed.

Reasons for our decision

9.34. We continue to believe that the IQI provides strong incentives for companies to put forward efficient forecasts and as such we are retaining the mechanism for RIIO-ED1.

9.35. In light of consultation responses and further discussions at price control working groups, we recognise that there needed to be some clarification of the interaction between fast-tracking and the IQI. We have decided that a fast-track DNO will receive a true-up to the outcome it would have received under the slow-track IQI matrix if it would have been better off under that matrix.

9.36. We do not consider that it is appropriate to relax the IQI matrix so that a company that is forecasting a higher cost than our upper quartile benchmark is able to break-even. To do so would increase the reward/reduce the penalties for all companies, including those who provide less challenging forecasts, without changing the incentives.

9.37. We believe that how we determine the upper quartile has to be taken into consideration as well. In past price reviews DNOs have criticised us for applying upper quartile benchmarking at a very disaggregated level, resulting in a "cherry picked" answer, which no one DNO can achieve across the board. Our cost assessment approach for RIIO-ED1 takes a more holistic approach to determining efficiency and as such our view of the appropriate rewards/penalties available in the IQI matrix reflects this.

9.38. We consider that including RPEs within the IQI provides strong incentives for companies to put forward efficient forecasts in this area. Including RPEs in the IQI reduces any incentives to load costs onto RPEs whilst proposing low unit costs for activities that feed into the IQI.

10. Encouraging innovation

Chapter Summary

This chapter sets out our decisions on the use of time-limited mechanisms within RIIO-ED1 to encourage innovation where this adds value to consumers. It also emphasises the importance of DNOs demonstrating that they are embedding innovation funded in past price controls within their business during RIIO-ED1.

Background and context

10.1. DNOs face significant challenges over the coming years, such as facilitating the transition to the low carbon economy. To meet these challenges cost efficiently, DNOs will need to try new operational, technical, commercial and contractual arrangements within their business.

10.2. Many elements of the RIIO price control framework are designed to encourage innovation, for example lengthening the price control period to provide companies with more certainty of the rewards for successful innovation. DNOs have had access to specific funding for innovation in DPCR5 through the Innovation Funding Incentive (IFI) and LCN Fund. We consider the LCN Fund has worked well and it is widely considered to have significantly improved the DNOs' attitude to innovation, knowledge sharing, anticipating the low carbon future and collaborative working with third parties.

10.3. We therefore expect DNOs to demonstrate clearly throughout their business plans that they have properly considered the use of alternative or innovative techniques in all areas of their business to deliver their outputs more efficiently. We expect to see concrete evidence of learning from IFI and LCN Fund projects being utilised within the DNOs' businesses.

10.4. We will take account of past and future innovation funding provided to DNOs in setting the efficiency frontier for the period (ie we would expect the high levels of innovation funding to date to allow DNOs to achieve results more efficiently).[45]

10.5. We consider that within the RIIO-ED1 framework there are strong incentives to innovate as part of normal business. For example, the IIS should encourage DNOs to anticipate the impacts of new loads and the efficiency incentive should incentivise DNOs to implement innovative solutions within their business, where they are more efficient than conventional approaches.

[45] Further information with respect to innovation in the business plans can be found in the 'Supplementary annex - Business plans and proportionate treatment'.

10.6. However, we also appreciate that certain research, development, trials and demonstration projects are speculative in nature and yield uncertain commercial returns. This is particularly true where benefits do not directly accrue to the DNOs and are linked to the role of energy networks in the transition to a low carbon economy. In September, we therefore set out the provision of a time-limited innovation stimulus package in RIIO-ED1 to provide additional funding for innovation initiatives that can benefit consumers but that DNOs would be unlikely to undertake in its absence.

10.7. The innovation stimulus will replace the LCN Fund and IFI that are part of the current price control, DPCR5. The final LCN Fund second tier competition will be held in April 2014 and funding awarded in that year (up to £64m) will be collected from consumers in 2015-16.[46] The LCN Fund also includes a discretionary reward. DNOs may be eligible for a discretionary reward upon successfully delivering the projects which are deemed to have delivered exceptional learning. As some projects will not be completed until after the start of RIIO-ED1, if any discretionary reward is allocated after April 2014 this will be recovered during RIIO-ED1. Funding will be recovered through DUoS charges and in accordance with the LCN Fund Licence Condition and Governance Document.

Our decision

Innovation stimulus

10.8. The innovation stimulus will apply to DNOs from April 2015. We will adopt broadly the same arrangements that have been adopted for RIIO-T1 and GD1. The innovation stimulus consists of three components:

- The Network Innovation Competition (NIC): a single annual competition for electricity transmission and distribution that funds large-scale, innovative projects with low carbon or other environmental benefits. Companies can apply to have a maximum of 90 per cent of the project costs funded through the NIC.
- The Network Innovation Allowance (NIA): a set use-it-or-lose-it allowance that each DNO receives to fund small-scale innovative projects as part of their price control settlement. The value of the NIA will be between 0.5 and 1 per cent of base revenues. The amount awarded to each DNO will depend on how well the DNO demonstrates in its innovation strategy that it has a well thought through plan to focus its innovation efforts over the price control period. DNOs will be able to pass through a maximum of 90 per cent of NIA expenditure.

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[46] Funding awarded under the LCN Fund second tier in 2014-15 will be recovered in 2015-16. The first NIC competition with transmission and distribution will be run in 2015-16 with funding recovered in 2016-17. Therefore there will be no overlap between the funding awarded under the NIC and LCN Fund, except for any discretionary reward that may be subsequently awarded.

- The Innovation Roll-out Mechanism (IRM): a revenue adjustment mechanism designed to make funding available for the roll-out of proven low carbon or environmental innovations within the price control period. The criteria for innovative solutions eligible for funding under the IRM will be included in a specific IRM licence condition. There will be two application windows for the IRM during RIIO-ED1. The first will be between during May 2017, the second during May 2019. The IRM will be subject to a materiality threshold[47] and the DNO must submit a relevant adjustment proposal for each innovation project being rolled out. The IRM cannot be used to recover innovation roll-out costs that have already been incurred.

10.9. The innovation stimulus can provide funding to all types of innovative solutions: technological, operational, commercial and/or contractual. DNOs will also be expected to collaborate with other parties and leverage external funding where possible.

10.10. We have developed with industry the licence conditions and governance documents that set out the regulation, process and procedures for the different components of the innovation stimulus for RIIO-T1 and GD1. They have been developed with DNOs with the intention of replicating these for DNOs from April 2015.[48]

10.11. Below, we have set out our decisions on the level and duration of electricity NIC funding from April 2015, and guidance on the innovation strategy requirements for RIIO-ED1.

Level and duration of electricity NIC funding

10.12. Innovation funding will be to be time-limited. DNOs have been provided with similar funding throughout DPCR5 to encourage a step change in how they approach innovation within their business. This funding is intended to kick start a cultural change where DNOs establish the ethos, internal structures and third party contacts that facilitate innovation as part of business as usual.

10.13. The funding cap for the electricity NIC will be £90m per annum in 2015-16 and 2016-17.[49,50] This includes the £30m already allocated for the duration of RIIO-T1. The £90m funding available is the maximum and we do not have to award any funding if projects are not of sufficient quality. Following

[47] One per cent of average RIIO-ED1 base revenue threshold
[48] The Licence Conditions and Governance Documents for RIIO-T1 and GD1 can be located athttp://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Pages/ConRes.aspx and http://www.ofgem.gov.uk/NETWORKS/GASDISTR/RIIO-GD1/CONRES/Pages/ConRes.aspx
[49] Flat in real terms, set in 2011-12 prices and inflated by RPI.
[50] There is a lag between when the competition is held and when funding is recovered, ie the first competition including distribution will be held in 2015, with the funding recovered the following year from April 2016.

completion of the majority of LCN Fund projects, we will undertake a learning review of the LCN Fund outcomes and use the findings to set the level and profile of electricity NIC funding for the remaining years of RIIO-ED1. We expect this review to take place in early 2016, so that a decision on funding for the remainder of RIIO-ED1 will be made by the end of the 2016 and in time to update the governance for the 2017 competition.

10.14. The funding for selected NIC projects will be recovered through Transmission Use of System charges in line with our March 2012 decision[51] and the existing electricity NIC funding mechanism.

Innovation strategy guidance

10.15. DNOs must submit an innovation strategy as part of their business plan submissions. This will set out their approach to innovation during RIIO-ED1 and beyond.

10.16. The innovation strategy should contain, at a minimum, the following information:

- the high-level problem(s) and/or challenge(s) which the sector/company expects to face over the period, and the justification for initiating projects to address these
- the process or methodology by which the company will decide the focus for innovation during RIIO-ED1
- demonstration that the problems/challenges have been identified/prioritised and justified in consultation with stakeholders
- discussion of the relative priorities, risks, benefits, value for money and potential customer impacts
- the consequences of innovation(s) not occurring
- deliverables and potential deliverables from the research or development or trials, such as defined learning on an issue, revised codes, new charging methodologies etc.

10.17. In addition, DNOs must set out in their innovation strategy information relating to the following three requirements:

- evidence of how DPCR5 innovation funding (ie IFI & LCN Fund) has been used effectively and resulted in improved outcomes for consumers
- a description of their approaches to ensuring the efficient roll-out of successful innovation into business as usual (including innovation developed by other DNOs)
- a description of their processes for reviewing and updating their innovation strategies within the price control period

[51] http://www.ofgem.gov.uk/Networks/nic/Documents1/March%20decision%20document%20Final.pdf

10.18. Based on the quality and content of a DNO's innovation strategy, we will set the NIA for the full duration of the price control period. The NIA will be between 0.5 and 1 per cent of base revenues. The default level of funding will be 0.5 per cent unless a DNO produces a clear, coherent and well justified innovation strategy that exceeds the minimum requirements and justifies fully why additional funding of up to 1 per cent is required. The DNO should indicate the level of NIA requested in the business plan data template. A DNO's NIA will not reflect whether they have been fast-tracked, it will be assessed on the quality of the innovation strategy alone.

Summary of our proposals

Role of innovation in RIIO-ED1

10.19. For RIIO-ED1, we proposed to implement the innovation stimulus broadly as it has been designed in RIIO-T1 and GD1 since we had designed it considering electricity distribution as well. We asked stakeholders if there were any aspects of the innovation framework for RIIO-ED1 that should differ from the RIIO-T1 and GD1 arrangements. We proposed limited changes, specifically relating to the level of funding for the electricity NIC and guidance on the requirements for the innovation strategy.

Level and duration of electricity NIC funding

10.20. In September 2012, we consulted on a proposed funding range of £60-90m per annum being available for the electricity NIC for 2015-16 and 2016-17.[52] We proposed to undertake a review of the learning and outcomes from the LCN Fund in 2016 in order to inform the level of funding from 2017 to the end of the price control.

Innovation strategy guidance

10.21. We consulted on whether we should revise the minimum requirements applicable under RIIO-T1 and GD1 and sought stakeholders' views about what essential information should be provided in the DNO innovation strategies.

10.22. We also asked stakeholders whether it was valuable for the DNOs to consult and update their innovation strategies regularly during the price control period.

[52] The competition will be held in 2015-16 and 2016-17 with the funding recovered in 2016-17 and 2017-18 respectively.

Summary of responses and reasons for our decisions

Role of innovation in RIIO-ED1

10.23. The majority of stakeholders noted the importance of innovation and welcomed our approach to innovation in RIIO-ED1. Two respondents noted that significant levels of innovation investment during RIIO-ED1 could be premature as the challenges and potential solutions are yet to be fully understood.

10.24. We acknowledge there is some uncertainty surrounding the speed with which these challenges will develop. However, the review of the level of electricity NIC funding in 2016 will allow us to review the existing levels of funding and have a clearer idea of the challenges DNOs will face in the future. This should help mitigate some of this uncertainty and we can then determine the appropriate level of funding for the remainder of RIIO-ED1.

Level of electricity NIC funding and review

10.25. Most stakeholders supported our proposed range of funding. Some responded that the funding threshold should be set at £90m. They noted that as the funding is provided at Ofgem's discretion, the entire amount does not need to be awarded each year. Some respondents argued that a lower cap may mean that some worthy innovation is not undertaken. Only one respondent stated that the proposed threshold may be too high, noting the future challenges and potential solutions may not be apparent yet. They stated that the current level of funding could lead to DNOs innovating at the expense of consumers.

10.26. We consider that DNOs will play a key role in facilitating the transition to a low carbon economy. Therefore incentivising them to innovate should help them do this in the most cost-effective way. Potential projects will be assessed against a set of evaluation criteria, which include how the projects provide value for customers' money. To receive funding, the DNOs will need to satisfy us that the project performs strongly against these criteria. We are not required to allocate the total funding available each year and will only award funding where we consider the projects meet the evaluation criteria sufficiently. In last year's LCN Fund decision[53], we awarded £45.5m, out of an available £64m of funding. Two project bids did not receive funding as we were not satisfied that the projects performed sufficiently strongly against the evaluation criteria.

[53] Last year's LCN Fund decision can be found http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=55&refer=Networks/ElecDist/lcnf/stlcnp/year3

10.27. All respondents supported our proposals to review the LCN Fund in 2016 and to revise the level of funding that will be available for RIIO-ED1 accordingly. Therefore, we will undertake this review in 2016.

Innovation strategy guidance

10.28. Generally, stakeholders were supportive of our proposals for DNOs to submit an innovation strategy, although each respondent had additional comments relating to certain areas of the business plans. Several respondents stated that the DNOs should include how previous approaches to innovation and learning from the LCN Fund have benefitted customers. Some respondents suggested that innovation strategies should include cost benefit analysis of innovation projects and another stated that the strategy should include clear processes to take ideas and concepts, through development, to initial deployment and then full scale adoption. Another respondent commented that DNOs' strategies should focus on priorities within their own network.

10.29. Two respondents commented that Ofgem should not be overly prescriptive as criteria may act as a barrier to innovation. One respondent noted that DNOs should identify the opportunities and potential benefits to customers. It commented that DNOs should have control over the information contained in their innovation strategy. We consider that the minimum requirements are high level information requirements that we expect to see in DNO innovation strategies. DNOs are free to expand on or provide any additional information in their strategy they deem is relevant for their stakeholders to understand their approach to utilising innovation funding. We expect the DNOs to produce an innovation strategy that is supported by its own stakeholders and identify their own priorities and business process for conducting and embedding innovation activities within their business.

10.30. We welcome the suggestions made and have identified three additional minimum requirements for the RIIO-ED1 strategies building on the suggestions made. The full list of minimum requirements for DNO innovation strategies can be found in the 'Our decisions' section of this chapter. We have also made some minor amendments to the wording of the requirements used in RIIO-T1 and GD1 to aid clarity.

Revising the innovation strategy within RIIO-ED1

10.31. The majority of respondents considered it would be valuable for the DNOs to update their innovation strategy within the RIIO-ED1 period. A number commented the DNOs are best placed to decide when this is necessary. Therefore we have outlined that the DNOs should provide a description of processes for reviewing and updating their innovation strategy within the price control period in their innovation strategy. We expect DNOs to then follow this approach during RIIO-ED1.

Changes to the innovation stimulus framework for RIIO-ED1

10.32. Respondents did not consider there were any additional aspects of the innovation framework that needed to differ from those in RIIO-T1 and GD1 (other than those identified above). A number of the DNOs commented that the development of the RIIO-T1 and GD1 arrangements through the Innovation Working Group, which they attended, meant they were broadly happy with the arrangements as they stand. Therefore we are not deviating from the framework developed for RIIO-T1 and GD1.

Appendices

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Appendix 1 – Summary of consultation responses

1.1. We received 49 responses to our September strategy consultation. Responses were received from the DNOs, National Grid, DECC, environmental groups, consumer groups and other stakeholders. Not all respondents answered each of the questions set out in the consultation documents. We have published non-confidential responses on our website as associated documents to the strategy consultation.[54]

1.2. The following is a summary of responses. We have summarized the views of respondents against each of the questions set out in the consultation.

Chapter Two

Question 1: We welcome respondents' views on the approach we have taken to develop the outputs framework.

1.3. All of the DNOs supported the approach taken to develop the outputs framework. One noted that six output categories were appropriate. No other respondents commented on this question.

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

1.4. Respondents did not think that our proposed output measures presented serious potential difficulties in ensuring the submission of accurate and comparable data. One DNO did not identify any difficulties. Other DNOs noted specific areas which may cause problems. One DNO felt that risk indices may require more data to be made more robust. Another DNO stated that if telephony were to be introduced it would create significant comparability issues. Other potential difficulties identified included comparability and consistency between DNOs in the new losses mechanism and the amount of data required for the time to connect measure.

1.5. One respondent highlighted that it is important that steps taken to improve comparability and harmonisation do not stifle innovation.

Question 3: Should we use a percentage of allowed revenue or £m set using basis points of return on regulatory equity (RORE) to set caps and collars?

54 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=36&refer=Networks/ElecDist/PriceCntrls/riio-ed1/consultations

1.6. Five DNOs and one supplier stated that we should use £m set using basis points of RORE to set caps and collars. One DNO indicated a preference for using a percentage of allowed revenue. No other respondents answered this question.

Question 4: Are there any aspects of our proposed outputs framework where the reporting requirements are likely to lead to disproportionate regulatory costs?

1.7. Most respondents did not identify issues with our proposed outputs framework where the reporting requirements were likely to lead to disproportionate regulatory costs. Two DNOs stated that it was not possible to comment with regard to social outputs because the reporting requirements were not sufficiently developed. One DNO felt that time to connect and HIs would involve more cost if taken to an inappropriate level of detail. Another DNO noted that criticality is only useful if assets are being replaced.

Chapter Three

Question 1: Do you agree that a specific output or incentive focussed solely on the connection of low carbon technologies is not necessary?

1.8. Most respondents, including five DNOs, agreed with our proposal that there is no need for a specific output or incentive focused solely on the connection of low carbon technologies (LCTs) as the desired behaviours are incentivised through various existing mechanisms. Two DNOs noted that it was difficult to differentiate between LCTs and other technologies and hence a specific output was not required. One DNO felt that a specific output was inappropriate because the adoption of LCTs were generally determined by factors outside the DNO's control. Another respondent supported the RIIO framework for incentivising the efficient delivery of a sustainable energy sector.

1.9. A number of respondents felt that although a specific output was not necessary, it was of primary importance that the DNOs facilitate the timely connection of LCTs. One respondent stated that there should be a specific requirement on DNOs to ensure that they delivered this.

1.10. Some respondents did not agree with our proposal. One environmental group suggested that there should be an overarching incentive for DNOs to work towards long-term decarbonisation goals. Another respondent felt that there needed to be an explicit incentive for the connection of LCTs because the proposed incentives relating to timely connections, network reliability and reinforcement were insufficient to drive LCT investment.

Question 2: Do you agree with our proposals on the level of detail DNOs will be required to submit on the different scenarios in their business plans?

1.11. Only the six DNOs and one other respondent answered this question. These respondents mostly agreed with the proposal. One DNO felt that each DNO should decide on the level of detail provided. Another DNO suggested that more detail was needed, in particular in relation to DG, energy efficiency forecasts and a number of other areas.

1.12. Some respondents also commented on the use of different scenarios in their business plans. These respondents approved of providing a DNO best view scenario. One respondent felt that the reference scenario should be one of the DECC medium scenarios, rather than the DECC low scenario as proposed.

Question 3: Do you agree that an uncertainty mechanism is required to manage the uncertainty around the penetration of low carbon technologies?

1.13. Most respondents agreed that an uncertainty mechanism was required to manage the uncertainty around the penetration of LCTs. All of the DNOs agreed in principle with the proposal. One suggested that it would require a high level of granularity or would need to be calibrated differently for each DNO. Another agreed but did not support Option 1 as set out in the proposal because it would affect some DNOs more favourably than others. One DNO suggested that expenditure within the volume driver should be included in the load-related reopener because unit costs are uncertain.

1.14. Three suppliers also agreed with the proposal. One supplier highlighted that it was important to ensure that DNOs put sufficient resources into developing forecasts and that any mechanism should be tightly capped. One environmental group agreed with the proposal but commented that the uncertainty mechanism should not inadvertently disincentivise the adoption of LCTs.

1.15. Two other respondents felt that neither of the options presented in the consultation were appropriate, one of which suggested that an uncertainty mechanism may not be needed at all.

Question 4: Do you agree with the three tier approach we propose to introduce for the recovery of the DNOs' costs during the smart metering roll-out?

1.16. Only the six DNOs and one supplier responded to this question. All respondents agreed with our proposed three tier approach. They noted that the three tier approach was pragmatic for the recovery of the DNOs' costs during the smart meter roll-out. A number of respondents noted that there was need for clarification about some aspects of the proposal. One DNO noted that there was uncertainty around suppliers' roll-out profiles, making it difficult to set allowances and volume drivers in advance. Another DNO felt that the smart meter reopener should be expanded to include all DNOs' costs. One supplier noted that the meaning of reasonable in the proposal needed clarification.

Question 5: Should costs of load and generation growth for existing customers in profile classes 1-4 be socialised, until smart metering data is available?

1.17. Most respondents felt that costs of load and generation growth for existing customers in profile classes 1-4 should be socialised, until smart metering data is available. One respondent noted that until smart meter data is available, it will be very difficult to ascertain which customers have caused network issues and therefore cost socialisation is a pragmatic approach. One consumer group approved of the proposal but stated that even before the mass roll-out phase of the smart metering programme, there might be sufficient data to move to a more cost reflective model, which would be preferable.

1.18. One DNO disagreed. It felt that it was more pragmatic and simple to use either the demarcation of half metering or voltage. Another respondent voiced concern that socialising these costs could lead to fuel poor customers incurring excessive costs. A number of respondents also noted that the use of smart meter data when it became available remained highly uncertain.

Question 6: Should DNOs retain the ability to charge existing customers in profile classes 1-4 who install equipment which poses significant power quality issues for the network?

1.19. All DNOs thought that they should retain this ability. One DNO noted that the current arrangements work well and ensure that customers who significantly affect power quality face the costs of addressing the problem. Another DNO suggested that costs should be socialised where it is not possible to clearly identify those responsible.

1.20. One supplier stated that the DNOs should have a role in ensuring that suitably accredited equipment is connected to their system. This would avoid the issues associated with the connection of this equipment and subsequent investment, thus improving the experience of the customer. Another respondent suggested the need for an incentive on consumers to invest in technology which had a lower network impact.

Question 7: If we socialise costs of existing profile classes 1-4 customers, will the use of system charging methodology need to be changed in order to protect IDNO margins?

1.21. Most respondents to this question thought that the use of system charging methodology would need to be changed in order to protect IDNO margins. One DNO noted that adjustments could be made to customer contribution assumptions in the charging model if socialised expenditure becomes significant, which would have the effect of increasing IDNO margins to reflect the additional expenditure. Another DNO stated that due to the way scaling works, the current methodology would result in all DUoS charges rising, therefore costs in the 1-4 profile classes would rise more than charges and the DUoS charging methodology would need to be changed.

1.22. One respondent made the general comment that the common distribution charging methodology would need to be changed to reflect all policy changed arising from RIIO-ED1. Another commented that it did not anticipate any 'margin squeeze' to occur for IDNOs with a portfolio of networks.

Chapter Four

Question 1: What are your views on the primary outputs and secondary deliverables for reliability and safety? In particular:

(a) Do you agree that these are appropriate areas to focus on?
(b) Are there any other areas that should be included?

1.23. The DNOs broadly agreed with the primary outputs and secondary deliverables for reliability and safety. They agreed that the areas set out in the consultation were the appropriate areas to focus on. They also made a limited number of specific comments. One DNO, for example, suggested that any costs related to the EGS2 standard that could not reasonably be managed by the DNO should be socialised across all customers. Another commented that the worst served customer mechanism needs to be revised to include an incentive scheme to encourage overall reductions in the number of interruptions experienced by customers.

1.24. No respondents put forward any major additional areas that should have been included. One DNO advocated that, with regard to load indices, a measure of priority/criticality should be included that recognises the short- and long-term drivers of asset maintenance and replacement. It also suggested that further work was needed before finalising the primary outputs and secondary deliverables for the final RIIO-ED1 framework.

Chapter Five

Question 1: Will our proposed approach ensure effective losses reduction actions?

1.25. Most respondents supported our proposed approach to ensuring effective losses reduction actions. One respondent supported the combination of approaches, noting that it allows for the deployment of low carbon technologies. A number of respondents agreed with the proposal but raised potential issues. One respondent suggested that the proposal could be overly complex and that more detail was needed on aspects of the cost benefit analysis and how to forecast incremental costs attributed to losses actions. One DNO warned that it could make DNOs indifferent to benchmarked reduction in energy consumed at substations.

1.26. Some respondents did not believe that a reputational incentive was effective. One suggested that DNOs should compete for a national losses allowance. Another suggested that an ex post review was needed. One DNO did not think that the approach could be extended to IDNOs. Other comments highlighted the role of energy conservation, energy efficiency and distributed generation in reducing losses.

1.27. One respondent did not support the overall approach proposed in the consultation. It proposed as an alternative activating a stronger version of the DPCR5 mechanism.

Question 2: Will our proposed losses discretionary reward provide the required incentive on DNOs to reduce losses? Should this be awarded twice during RIIO-ED1 or more frequently?

1.28. Three DNOs considered that the level of the reward was appropriate and that it would place the required incentive on DNOs to reduce losses. Two DNOs and one consumer group felt that the reward was insufficient and should be larger in order to have its desired effect. Respondents also noted that there was need for clarity on the interaction of the reward with the IQI and a need to ensure that DNOs are not rewarded twice through different incentives.

1.29. Two DNOs and one supplier agreed that the reward should be awarded twice during RIIO-ED1. One DNO noted that this would ensure that measures implemented give long-term benefits. One DNO and two suppliers suggested that it should be awarded every two years, and one supplier felt that an annual award would support sustained performance.

Question 3: Should DNO actions to identify and address electricity theft be encouraged through an approach outside of any losses reduction mechanism? Do you have any views on the proposed approach, or any alternate proposals, that we should consider?

1.30. Most DNOs supported our proposed approach for DNOs to identify and address electricity theft through a separate mechanism. They noted that DNOs should address theft where necessary and that costs of theft reduction actions must be recoverable, and should be covered as per Schedule 6 of the Electricity Licence. One DNO stated that costs for investigating and resolving unregistered premises should be allowed in base revenue. Two other respondents fully supported our proposals.

1.31. One supplier felt that a specific approach to vulnerable customers should be set out. Another supplier raised concerns that DNOs were 'double recovering' on some items. One DNO did not accept that theft was a DNO issue and did not believe that DNOs should identify and address theft outside of the losses mechanism.

Question 4: Do you think that further guidance should be provided with regard to the use of the '10 per cent allowance' for undergrounding? If so, what form should this guidance take?

1.32. Responses to this question were mixed. Three respondents felt that there was no need for further guidance because there was already sufficient clarity as to how it should be used. One DNO noted that the examples given provided a 'steer' whilst not being prescriptive or constraining the flexibility that this allowance should encourage.

1.33. Seven respondents felt that more guidance would be beneficial but most emphasised the point that this guidance should not be prescriptive. Two respondents noted that there was a need for greater clarity in terms of how and when it can be applied, particularly outside of NSAs and AONBs. A number of respondents commented that the use of best-practice case studies would be an appropriate form for this guidance to take.

Question 5: Are National Scenic Areas (NSAs) sufficient to allow for effective use of the scheme in Scotland in the protection of visual amenity?

1.34. All respondents agreed that NSAs were sufficient. Two respondents noted that accurate reporting would be required to ensure that no double-counting occurred in areas that have dual designations. One DNO commented that the inclusion of NSAs should depend on them being comparable to AONBs and that extra funding should be considered to avoid the risk of reducing funding available for undergrounding in other areas. Some respondents noted that the density of lines in NSAs is relatively low and that the mechanism could deal with growth by scaling any allowances to reflect actual growth.

Question 6: Do you agree with our proposals with regard to DNO assessment and stakeholder engagement within the undergrounding scheme?

1.35. Five DNOs responded to this question and agreed with our proposals. Two DNOs noted that they agree that the assessment and prioritisation of undergrounding projects should remain with the DNO, except in the case of AONB. One environmental group thought it was appropriate for there to be a published policy outlining the process of assessment and prioritisation of projects by DNOs and suggested that it should concentrate on the stages of the process. Another environmental group suggested that current best practice should be used rather than each DNO evolving their own assessment practices.

1.36. Three environmental groups supported our proposal to publish policy documents outlining the options available to stakeholders for engagement and project support from DNOs. They all emphasised the importance of stakeholder engagement in this area. One noted that the publication should include the format in which stakeholders should request support. Another remarked that DNOs should be tasked with identifying their stakeholders and appropriate representatives of these groups.

1.37. One DNO highlighted that these published policies should not be prescriptive or constrain the diversity of approaches taken by the DNOs in stakeholder engagement. Another respondent supported our proposals but noted that they should not be allowed to lead to additional bureaucracy or increased costs which reduce funds available for undergrounding.

Question 7: Do you agree with our proposed approach for BCF? Do you consider there are any additional elements that should be included within the BCF reporting scope?

1.38. All the DNOs broadly agreed with our proposed approach for BCF. One noted that it was appropriate to strengthen the reporting to include proactive activities because this reduced the risk of any reputational incentive being based on the incorrect interpretation of data. Another DNO commented that they should be provided with guidance to ensure comparability.

1.39. One consumer group felt that BCF reporting created a weak reputational incentive on DNOs and that it would not motivate them to reduce their environmental impact. One DNO felt that exceptional events should be removed from the BCF and that additional activities which are less easily measured should be included, such as waste management or recycling. One environmental group felt that BCF could be more detailed and proposed that DNOs should report net carbon figures.

Question 8: Do you agree with our proposed approach to SF6 monitoring, reporting and management?

1.40. The DNOs broadly agreed with our proposed approach. Five DNOs agreed that reporting of SF6 should be enhanced. One DNO agreed that control measures should be implemented to monitor and minimise leakages. Another DNO did not think that SF6 regulatory reporting should be increased given increases in statutory SF6 regulation.

1.41. One DNO felt that it was appropriate to ensure DNOs are compliant with international standards. An environmental group welcomed the proposals and supported raising awareness of forthcoming legislation.

Question 9: Do you agree with our approach for fluid filled cables?

1.42. All DNOs agreed with our approach for fluid filled cables. One environmental group also welcomed the proposed approach, noting that effective reporting ensures that progress is monitored.

Question 10: Do you agree with our approach to noise reduction?

1.43. Only five DNOs responded to this question. Four DNOs broadly agreed with our approach to noise reduction. One commented that Ofgem should clarify how to consistently report projects undertaken by DNOs where the primary purpose was to reduce noise. Another noted that the level of expenditure in this area is very small, and hence it is appropriate to remove it from environmental expenditure reporting, although a small portion of the environmental allowances should be retained to undertake such schemes.

1.44. One DNO disagreed with our proposed approach. It felt that it was contradictory to proposals in other areas to remove the reporting requirement and that since companies do incur expenditure to tackle noise reduction this should be reported. It stated, however, that the current reporting requirements were not appropriate and suggested that reporting was amended to provide space for explanatory narrative.

Question 11: Do you agree with our assessment of the need for an additional environmental discretionary reward?

1.45. Two respondents stated that there was not a need for an environmental discretionary award and five respondents stated that there was. Two DNOs suggested that the losses discretionary reward should be expanded to encompass all environmental objectives, supported by an increase in the reward available.

1.46. One DNO commented that an EDR would be an efficient way to drive behavioural change. Another DNO felt that certain areas, such as waste management, would benefit from an environmental discretionary award (EDR). Two environmental groups also noted that there was a need for an overall environmental incentive and that an EDR could potentially create a strong incentive for DNOs to take appropriate action.

Chapter Six

Question 1: Do you agree with our proposal to retain the Broad Measure of Customer Satisfaction (BMCS) and increase the maximum revenue exposure?

1.47. DNOs and other respondents were broadly supportive of our proposals. DNOs agreed with retaining the BMCS and increasing the maximum revenue exposure although some highlighted areas for improvement. Two DNOs noted that the maximum penalty had increased to a greater degree than the maximum reward, which they felt not to be appropriate. One DNO felt that the percentage increase for connections customers was too high.

1.48. One supplier disagreed with the proposal to increase maximum revenue exposure. One consumer group questioned whether BMCS delivered value for money.

Question 2: We seek views on the approach to setting targets for the RIIO-ED1 period, including whether these targets should be fixed for the price control period or should be responsive to changes in industry performance.

1.49. Responses received were mixed regarding whether targets should be fixed for the price control or responsive to changes in industry performance. Four DNOs indicated a preference for fixed targets. They noted that fixed targets gave certainty for investment planning and should effectively incentivise DNOs to improve performance. One DNO felt that fixed targets were preferable but suggested a mid-point review to reflect the impact of industry developments such as the rollout of smart meters.

1.50. Three respondents (one DNO, one supplier and one consumer group) did not think that fixed targets were appropriate and indicated a preference for responsive targets to allow for targets to reflect industry developments. One respondent had reservations on the effectiveness of the approach to setting targets altogether, noting that customer satisfaction surveys can be highly subjective.

Question 3: We seek wider stakeholder views on whether interruption customers that have been proactively contacted by the DNO via new methods of communication (eg social media) should be included in the customer satisfaction survey.

1.51. One DNO fully supported the inclusion of new methods of communication. Most respondents stated that new methods of communication should not be included unless customers were contacted via a specific and identifiable contact channel. They felt that it was inappropriate to include more general customer contacts. One consumer group commented that further work was required to assess how new communication channels, such as social media, could be measured and used to develop appropriate incentives.

Question 4: Should the provision of information to connections customers be taken into account when calculating the score of the customer satisfaction survey?

1.52. Most respondents did not think that it was appropriate to place additional weight on the provision of information to connections customers in the customer satisfaction survey. Four DNOs did not think the provision of information needed to be taken into account separately because the existing measures already reflected customers' views on this issue and were therefore satisfactory.

1.53. One DNO considered it to be a significant issue for connections customers, but one that would be better assessed against objective criteria rather than subjective responses to a survey. Another respondent suggested that it should be taken into account and this could be done by increasing the weighting on the information provision element of the questions for customers whose details are available.

Question 5: Should the number of unsuccessful calls be taken into account when calculating the score of the customer satisfaction survey?

1.54. Only DNOs responded to this question. Four DNOs felt that the number of unsuccessful calls should be taken into account. They noted that it was an important consideration and that it should be trialled before it is introduced.

1.55. One DNO highlighted that this needs careful consideration to ensure it avoids creating perverse incentives to reduce the flow of calls. Another did not think that it should be taken into account, noting problems with common definitions and auditing in the past, and suggesting that eventually customers will get through and would then be eligible for interview.

Question 6: What indicators should we use to measure complaints performance? How should these be weighted?

1.56. Only DNOs responded to this question. One respondent felt that the existing weightings were satisfactory. Another agreed with our proposals, including maintaining the principle that the absolute number of complaints should not be incentivised and the proposal to adjust the weighting given to Energy Ombudsman (EO) decisions that go against the DNO.

1.57. Other respondents agreed with the indicators and weightings proposed with few suggested improvements. Two respondents agreed with the approach with the exception of EO decisions. One felt that it should be assessed against the total number of complaints and the other suggested that its weighting should be reduced.

Question 7: How should we calculate the BMCS complaints metric target for RIIO-ED1? How should we calculate the score at which the DNO incurs their maximum penalty exposure?

1.58. Only the DNOs responded to these questions. Two respondents stated that the approach should be the same as in RIIO-GD1 and RIIO-T1. Other respondents suggested that the complaints metric target should be calculated against a fixed benchmark based on the historical performance of all DNOs and by taking an average of upper quartile performers.

1.59. One respondent felt that the current maximum penalty was unlikely to be reached and that a new score should be calculated through modelling when a second year of data could be assessed. Another suggested that the maximum penalty should apply where performance is worse than a multiple of the benchmark figure.

Question 8: Do you agree with the proposed approach to assessing stakeholder engagement?

1.60. Respondents broadly agreed with our approach. Positive comments included that the additional rewards should assist DNOs looking to invest in this area, and that increasing the reward from 0.2 to 0.5 per cent sets a clear incentive. One respondent noted that guidance should be clearly communicated and should enable proposals of innovative solutions. Respondents stressed that it was important that the minimum requirements were clearly communicated at an early stage.

1.61. One environmental group highlighted that stakeholder engagement should be geared towards the needs of the various stakeholders rather than the convenience of the DNO.

Chapter Seven

Question 1: Are there additional social issues that the DNOs should address?

1.62. One DNO identified an additional social issue in the form of assisting agencies such as the police to address issues such as increased electricity use in cannabis farms. However, in general they agreed that their activities should be focussed on supporting vulnerable consumers and that they should work in partnership with other agencies responsible for the health and well-being of residents. This would identify any further issues and increase awareness of the additional support to which eligible households are entitled. This engagement and promotion would be incentivised via the Stakeholder Engagement initiative. One respondent noted that as DNOs provide a monopoly service, they are well placed to deliver social actions and support work to alleviate fuel poverty in a cost-effective manner.

1.63. Other respondents felt that the additional social issues that the DNOs should address fall into two broad categories: (i) those which seek to enhance the current obligation to maintain a Priority Services Register (PSR) in order to provide additional support to vulnerable consumers (ii) those which suggest additional issues that DNOs could address. In particular, some felt that DNOs should, wherever possible, through links to the social obligation placed on GDNs and suppliers, do more to address vulnerable off-gas grid customers (and also off electricity-grid in national parks) to provide reasonable grid-connection opportunities. These included the socialisation of network reinforcement costs with regards to the installation of low carbon heating.

Question 2: Are there any specific outputs that the DNOs could be responsible for delivering?

1.64. DNOs did not identify any specific outputs that they could be responsible for delivering and felt that careful consideration would need to be given to the organisation or mechanism through which DNOs report information about customers in fuel poverty. However, there was reference to activities that sought to enhance current obligations on the PSR. These included; improving data captured by DNOs about vulnerability and seeking to target or support the production of relevant publications, such as Braille, to ensure that supportive information on the benefits of the PSR is distributed effectively within relevant networks. A number of respondents felt that DNOs should play a greater role in the identification of customers in fuel poverty, particularly those off the gas grid.

1.65. One respondent proposed that a DNO could be incentivised for the length of their cabled network that is shared with another utility (such as broadband), either over or underground. They could also be responsible for delivering connections for off-gas and off-electricity grid customers as well as the installation of low carbon measures to low-income households, to avoid the use of expensive fuels and network reinforcement. For example, a DNO may be able to replace electrically heated tower blocks with a contribution towards a modern efficient district heating network, extensive insulation with a potential link up to Green Deal and ECO (or gas connections in blocks of less than three storeys). The contribution by the DNO to the cost of these alternative projects would always have to be lower than the cost of the network reinforcement.

1.66. It was also suggested that DNO assistance could be delivered in a number of ways (potentially involving direct rebates to households, liaising with a gas network to enable a connection to the gas grid or helping to identify alternative electric heat technologies or energy efficiency improvements). One respondent highlighted that network companies could charge a lower cost to customers (reduced or zero Use of System charges) on the PSR if there is an effective mechanism to discount these charges by the supplier as a rebate on energy bills.

Question 3: Should a separate funding allowance be provided to enable DNOs to carry out activities in response to social issues?

1.67. The majority of responses stated that a separate funding allowance would only be appropriate if the activity can be clearly identified and supported by stakeholders. However, in general respondents agreed that the increased stakeholder engagement funding should include the identification of initiatives to deal with social issues and the coordination of partnerships and mobilisation of local networks and resources to support vulnerable customers. These respondents considered that DNOs should be encouraged to consider their social obligations as part of core business and not a corporate social responsibility activity which is additional to main business.

1.68. A minority of responses felt that consideration should be given to an innovation fund to explore projects that benefit fuel poor customers. However, they considered that Ofgem should clarify any ambiguity that leads DNOs to believe that social action by them is potentially restricted solely to engagement on issues relating to the PSR. It was felt that there is a significant opportunity to incentivise DNOs to work with different parties to take a longer-term view of reinforcement requirements on their network, leveraging additional funds based on other parties and making sure the investment is cost effective, but also ensuring that there is a direct social outcome.

Question 4: Are DNOs adequately incentivised to engage with social issues as part of the BMCS Stakeholder Engagement incentive?

1.69. Respondents largely agreed that DNOs are adequately incentivised to engage with social issues as part of the increased Stakeholder Engagement incentive. However two respondents noted that it did not encourage investment in innovative approaches or encourage other DNOs to adopt best practice.

Chapter Eight

Question 1: Do you consider that our proposed package will drive the appropriate behaviour for connecting both demand and generation connections?

1.70. Respondents generally considered that our proposed package would drive the appropriate behaviour for connecting both demand and generation connections. They commented that a technology neutral approach was appropriate, and that it would incentivise DNOs to perform beyond GSOP timelines.

1.71. Some respondents raised concerns about our proposed package. Three respondents did not think the package provided sufficient incentives to connect DG.

One DNO stated that the DG incentive should be maintained for RIIO-ED1. Another DNO felt that there was a significantly higher risk of penalty, but only a marginal increase in potential reward, in comparison with DPCR5.

1.72. Other comments noted that connection incentives should be removed in market segments that pass the competition test and that this should be achieved proportionally. One DNO felt that more clarity was needed in some areas which could lead to perverse incentives, such as a time to connect for major connection customers who may require very long timescales for their connection.

Question 2: Is it appropriate to remove the DG incentive?

1.73. DNOs and suppliers mostly agreed that it was appropriate to remove the DG incentive, but other respondents generally disagreed. Five DNOs and two suppliers commented that it was appropriate to remove the DG incentive, in particular considering the changes to connections anticipated through the RIIO-ED1 period. They felt that the DG incentive was no longer necessary because DG was sufficiently covered by other mechanisms, including information incentives and the time to connect incentive. They suggested that uncertainty in forecasting DG could be managed through a load related reopener. One DNO stated that generation and demand should be treated equally because it was not practical to determine which caused reinforcement. Two DNOs and one supplier agreed that the DG incentive was not necessary but thought that there should be an uncertainty mechanism related to DG.

1.74. One environmental group stated that forecasting DG was particularly difficult and that there needed to be an incentive on DNOs to support DG development and to encourage engagement with the DG community. Two other respondents felt that the proposed uncertainty mechanisms and incentives that would apply to DG did not provide sufficient incentives to encourage DG connection, and that a specific DG incentive should remain.

Question 3: Do you agree that we should split the BMCS customer satisfaction survey into major and minor connections customers? If not, why not?

1.75. Most respondents supported splitting the BMCS customer satisfaction survey into major and minor connections customers. All the DNOs agreed. They noted that a "one size fits all" approach may not reflect major customers' requirements and those customers in market segments which have passed the Competition Test should not be subject to incentive regimes. They suggested that careful attention should be paid to the design of the survey and raised concerns about small sample sizes for some relevant market segments. One DNO agreed with the split but thought that the existing survey already achieved this distinction, and therefore introducing a new qualitative survey was unnecessary.

1.76. Suppliers supported splitting minor and major customers to ensure that major customers were represented. One respondent suggested that analysis should be carried out to demonstrate the effectiveness of the BMCS.

1.77. One consumer group supported the differentiation and also suggested that there could be additional positive discrimination for community-led DG, for example avoiding reinforcement costs, although it noted that this would be difficult to define in a robust manner. Another respondent commented that unmetered customers needed to be recognised as a separate group within the major category.

Question 4: How should we set targets for the BMCS customer satisfaction survey?

1.78. All respondents considered that we should set fixed targets for the BMCS customer satisfaction survey. They noted that this was the same approach as used in RIIO-GD1 and that it would allow for the sharing of best practice. Respondents felt that fixed targets were preferable because they provided clear signals for improvement and made evaluation and justification of actions easier. One respondent suggested that targets should be set individually for each DNO based on historic performance.

1.79. One DNO suggested that a mid price control review might be beneficial in order to respond to any changes in the industry. One supplier proposed that the fixed targets were ratcheted up across RIIO-ED1.

Question 5: We invite views on our proposals for the Long Term Development Strategy (LTDS), DG Connection Guide and Information Strategy (IS).

1.80. The majority of respondents agreed with our proposals. All respondents noted that the LTDS and the DG Connection Guide were useful and therefore it was appropriate for them to remain in place during RIIO-ED1. The majority of respondents also agreed that there was no further need for a more prescriptive IS, noting that DNOs were incentivised to meet customer information needs through other mechanisms. One DNO considered that its customers had highlighted the usefulness of the IS and therefore supported the existing framework.

Question 6: Are additional or alternative incentives required to encourage the DNOs to provide better information to connection customers upfront? If so, what would these measures and incentives be?

1.81. Most DNOs did not think that additional or alternative incentives were required. They noted that incentives already in place are sufficient to drive the required behaviour. One DNO felt that additional incentives were required and that this could be achieved through a specific weighting on a customer satisfaction survey question. Another DNO queried how an incentive would work as part of the customer satisfaction survey and suggested that it might be necessary to consider alternative arrangements for market segments that pass the competition test.

1.82. Other respondents commented that the ability to charge upfront for assessment and design fees was appropriate and should improve the connections process for customers. One also suggested that the connection quotation template should be standardised across all DNOs.

<u>Question 7:</u> We seek stakeholders' views on the introduction of a new Average Time to Connect Incentive.

1.83. Most respondents supported the introduction of the incentive and felt that it would lead to improvements in the connections process. DNOs all agreed that the introduction of a new Average Time to Connect Incentive would be beneficial. They noted that it was important that the size of risk and reward was proportionate. One DNO suggested that the incentive was reviewed at a mid period review to ensure that it is delivering appropriate outputs.

1.84. Some respondents suggested that the Average Time to Connect Incentive should not apply to major customers. They felt that for major customers, the main concern relates to certainty of delivery or willingness to explore options rather than end-to-end speed of process. They therefore felt that incentivising the Average Time to Connect could lead to perverse behaviour.

1.85. Some respondents did not think that introducing the incentive was appropriate. One environmental group felt that it may lead to unsatisfactory outcomes for customers. Respondents also remarked that this incentive may stifle competition by giving DNOs an unwarranted income stream that was not available to competitive providers of connections, and that it should not be applied to relevant market segments in which DNOs have passed the Competition Test.

<u>Question 8:</u> We seek views on which aspects of service should be measured, the approach used for target setting and whether any exemptions should be applied under the Average Time to Connect Incentive?

1.86. One DNO felt that it was appropriate to split the measurement between (i) time to quote and (ii) time from quote acceptance to completion. Another stated that the incentive could measure the time to connect or the percentage achievement of agreed time to connect. For high volume, low cost connections, it thought it was appropriate to measure the total time to complete works, and for low volume, high cost connections, the percentage of variance from agreed time to connect should be measured. Another suggested that measurement should avoid "stop the clock" provisions which could create an incentive not to resolve issues.

1.87. DNOs had differing views on the approach used for target setting. One felt that individual targets would be more appropriate for major customers to reflect the difference between networks and other regional factors. One indicated a preference for fixed targets based on historical performance, which should be subject to a mid-period review. Another stated that targets should be DNO specific and set for each Relevant Market Segment.

1.88. Most DNOs supported application of some exemptions under the Average Time to Connect Initiative. They felt that exemptions should be allowed for delays caused by factors that are outside the control of the relevant DNO.

Question 9: Do you agree with our proposed approach for the treatment of connection customer contributions by the DNOs during RIIO-ED1?

1.89. Respondents broadly supported our proposals. DNOs made a number of specific comments and recommendations. They noted that it should remove the perceived level of risk associated with strategic investment in anticipation of future demand, which would improve the timeliness of connections. One DNO suggested that the mechanism should only apply to connection assets that do not form part of the Regulatory Asset Value. Another DNO remarked that the proposed approach removes an out-performance opportunity for the DNOs and reduced the attractiveness to investors. Other comments included the need for further clarity and simplification and the need to ensure that it does not create an incentive for DNOs to invest in significant reinforcement where connections do not materialise.

1.90. One supplier and one other respondent also agreed with our proposed approach.

Question 10: Are additional incentives needed to encourage the DNOs to provide high-quality, timely non-contestable work? If so, what incentives should be applied?

1.91. Most respondents did not think that any additional incentives were needed. Five DNOs felt that sufficient incentives were already in place. They noted that Standard Licence Condition 15 worked well and that the development of effective competition would drive improvements. One DNO felt that additional incentives were needed.

1.92. One other respondent stated that DNOs should be incentivised to publish more information in order to free up resources for legitimate connection applications.

Question 11: We seek views on the financial exposure and scope of incentives for those market segments that have/have not passed the Competition Test.

1.93. DNOs generally agreed with our proposals. They noted that they were balanced and provided an incentive to pass the competition test. They agreed that BMCS and Time to Connect should be withdrawn for market segments that pass the competition test. One DNO commented that the incentives in market segments that do not pass the competition test should be proportionate and that approximate market value could be estimated for each market segment. Another suggested that in market segments that do pass the competition test, the potential upsides/downsides should be proportionately adjusted, in line with the average value of these market segments to a specific DNO.

1.94. Some DNOs raised concerns that they could be unfairly exposed to a penalty when a market segment did not pass the competition test for reasons beyond their control. They suggested that we consider redefining these market segments as Excluded Market Segments. DNOs also expressed concerns about the potential level of penalty DNOs would be exposed to, based on very small sample sizes for Relevant Market Segments that do not pass the competition test.

1.95. One supplier advocated that interruptions and general enquiries components of the customer satisfaction survey should still apply in market segments that pass the competition test. Another respondent questioned the effectiveness of the competition test in determining whether effective competition exists and highlighted the risk of a "detriment gap" between competition not working and Ofgem deciding to make a reference to the Competition Commission.

Chapter Nine

Question 1: Do you agree with our proposed range for the efficiency incentive rate?

1.96. Respondents mostly agreed with our proposed range for the efficiency incentive rate. One DNO agreed with the proposed range but stated that the consequent increase in risk should be reflected in the allowed cost of equity or lower gearing. Another DNO stated that it would not be appropriate for a fast-track company to receive a lower incentive rate than a slow-track company, and therefore fast-track companies should receive a 70 per cent efficiency rate and the IQI matrix should only apply to slow-track companies.

1.97. One respondent felt that a range of 60 to 70 per cent was more appropriate.

Question 2: Do you agree with our proposed approach to the calibration of the IQI?

1.98. DNOs raised a number of concerns regarding our approach to the calibration of IQI. DNOs' comments suggested that the proposed IQI calibration should reward companies whose forecasts are accepted without adjustment, as in DPCR5 and RIIO-GD1. They felt that the proposed approach did not provide a financial incentive for DNOs to meet their forecasted expenditure and suggested that the approach should be consistent with DPCR5, RIIO-GD1 and RIIO–T1.

1.99. One stated that RPEs should be excluded from the IQI assessment because it should not be subject to additional efficiency adjustments. Another DNO remarked that the proposed approach would have a significant downward impact on return on equity, compared to DPCR5, due to a large downward adjustment to the IQI associated income. It felt that the likely outcome of the approach was an expected return lower than the allowed cost of capital and that the approach required revision.

Question 3: What are your views on the indicative IQI matrix?

1.100. The DNOs were generally critical of the indicative IQI matrix. One commented that the IQI matrix from DPCR5 should be retained. It felt that the proposed matrix would lead to negative outcomes. For example, one suggested that it would result in a DNO being penalised via loss of allowance and penalised again via negative additional income through the IQI and a substantial reduction in the expected return on equity. Others noted that the matrix seemed to penalise slow-track companies rather than reward fast-track companies.

Question 4: What do you consider are the appropriate rewards for fast-track companies compared to non fast-track companies? Should we have a differential between the two?

1.101. Most DNOs agreed that there should be a differential between fast-track and non fast-track companies. They stated that there should be strong rewards for fast-track companies and that under no circumstances should non fast-track companies receive a more favourable financial package. One DNO highlighted that fast-tracked companies will submit the most challenging cost forecasts and thus deserve an adequate reward. Additionally, if a non fast-track company receives and IQI assessment that grants it a larger reward or a more favourable package, the fast-tracked company should qualify for the same amount.

1.102. One DNO suggested that the same matrix should be applied to fast-track and non fast-track business plans. It felt that fast-track companies should benefit from an IQI ratio of 100 and that non fast-track companies should be eligible to do so. Another stated that if a company was not fast-tracked due to concerns relating to limited specific elements of their business plans, it could under some circumstances benefit from the IQI matrix.

1.103. Most DNOs agreed that the IQI matrix was an appropriate mechanism for rewarding fast-track companies. One noted that fast-track companies should receive an incentive rate at the top of the range and an additional reward. It also felt that using a range was more appropriate than a fixed percentage for the additional reward until Ofgem have a clearer view on DNO business plans. Another suggested that the additional reward of 2.5 per cent of totex used in RIIO-T1 and GD1 was appropriate for RIIO-ED1.

Question 5: Do you agree with our proposals for the same efficiency incentive rate to apply to all areas of expenditure that will be included within the IQI?

1.104. All respondents agreed that the same efficiency incentive rate should apply to all areas of expenditure that will be included within the IQI. One respondent noted that this would remove any remaining boundary issues on cost classification. A number of DNOs, however, identified elements that they did not think should be included in the IQI. One did not think that transmission exit charges should be included in the framework. Another stated that expenditure associated with uncertainty mechanisms should not be included in the IQI assessment to avoid companies being unduly rewarded or penalised for differences in forecasts on uncertain items. One DNO remarked that RPEs should be dealt with via an appropriate and distinct uncertainty mechanism. Another did not think that it was appropriate to include incremental deficit costs because areas outside the control of DNOs should not be subject to a sharing mechanism.

Question 6: Do you agree with our proposed treatment of DNOs within a single ownership group? If you disagree with our proposals in these areas, please explain the basis for an alternative approach.

1.105. The DNOs' responses to this question were mixed. Three agreed with the proposal. They felt that establishing IQI ratios by assessing the sum of all expenditure forecasts of DNOs within a single ownership group was appropriate. They commented that although having to wait for the outcome of the non fast-track DNO(s) review to calculate the overall IQI ratio was not a significant drawback, it would be preferable if all DNOs within a group were fast-tracked or not.

1.106. One DNO noted that it would be better to derive the overall ratio from an aggregate IQI rather than by weighting the individual ratios by share of totex. Another DNO felt that DNOs within a single ownership group should not receive the same treatment.

Chapter Ten

Question 1: Do you agree that the cap on funding for the electricity NIC should be within the range of £60m and £90m for 2015-16 and 2016-17? Please provide evidence to support your suggested level of funding.

1.107. Six respondents stated that they believe the funding threshold should be set at £90m. They noted that as the funding is provided at Ofgem's discretion the entire amount does not need to be awarded each year and a lower cap may mean that some worthy innovation is not undertaken. Two respondents agreed with the proposed range of funding. Two respondents stated that they had no comment on the level of funding available. One respondent stated that the proposed threshold may be too high as the future challenges and potential solutions are not yet apparent. It stated the proposed level of funding could lead to DNOs innovating at the expense of consumers.

1.108. One respondent disagreed with the discontinuation of the LCN Fund. We note, for the avoidance of doubt, that the NIC will be replacing the LCN Fund and will serve a similar purpose.

Question 2: Do you agree that the level of funding for the rest of the RIIO-ED1 period should be reviewed in 2016 following a review of the LCN Fund?

1.109. All respondents agreed that there should be a review of the funding threshold after two years. Two respondents commented that the review should look at the rate/efficiency of innovation from the LCN Fund being taken up into business as usual activities. One of these respondents also stated the review could investigate how to encourage the take up of LCN Fund innovation to business as usual. One respondent stated that a provisional funding cap for the entire RIIO-ED1 period should be announced to avoid uncertainty. One respondent registered surprise that the NIC will not continue after 2017.

Question 3: What are your views on the information DNOs should provide in their innovation strategies? How can DNOs best demonstrate that their approach to innovation is sufficiently well justified and robust?

1.110. The responses to this question were supportive of our proposals although each respondent had additional comments relating to certain areas of the business plans. One respondent stated the proposed level of detail should be the minimum. Several respondents commented that innovation strategies should include how learning from the LCN Fund has been used effectively.

1.111. One respondent stated the DNOs should include the approach to innovation undertaken over recent years and explain how this approach has benefitted customers. The respondent supported the proposed pre-registering of NIA projects but opposed including details of proposed NIC projects in the strategy due to the competitive nature of the fund.

1.112. Another respondent commented that justification for innovation should be provided with specific examples. They also commented that DNOs should have control over the information contained in the strategy and that it should reflect stakeholder feedback and learning from the LCN Fund. One respondent stated that the strategy should include clear processes to take ideas and concepts, through development, to initial deployment and then full scale adoption.

1.113. Several respondents commented that Ofgem should not be overly prescriptive as criteria may act as a barrier to innovation. One respondent queried the level of detail required to achieve the higher level of the NIA. Another respondent stated that the strategies should include cost benefit analysis of chosen innovation compared to other options.

Question 4: Do you agree that it would be valuable for DNOs to consult and update their innovation strategies regularly during the price control period?

1.114. All respondents agreed that innovation strategies should be updated during the price control period. Four respondents stated that they believe the process should not be overly prescriptive. One respondent commented that there should be an enforced roll-out of proven innovation to business as usual.

Question 5: Are there any aspects of the innovation framework for RIIO-ED1, which you think should differ from the arrangements from RIIO-T1 and RIIO-GD1? If yes, please explain why.

1.115. All respondents agreed that the RIIO-ED1 arrangements should be similar to the RIIO-T1 and GD1 arrangements. Two respondents commented that the low carbon transition will have a greater impact on electricity distribution networks compared with transmission and gas distribution networks. They believe the arrangements should be mindful of these additional impacts. One respondent stated that one reopener window for the IRM is too restrictive.

Appendix 2 – Competition in Connections

Background

1.1. DNOs do not have a natural monopoly on the installation of new connections. ICPs and IDNOs can compete with DNOs to complete some connection activities.

1.2. The activities that ICPs/IDNOs can undertake are described as 'contestable activities'. Contestable activities include the design, procurement and construction of the sole use connection assets. Those activities that can only be carried out by the DNO are described as 'non-contestable'. Non-contestable activities currently include determining the point of connection to the distribution system and undertaking upstream reinforcement to the distribution system.

1.3. During DPCR5 we set out arrangements to facilitate the development of competition for contestable services in the electricity connections market. We specified segments of the market (the Relevant Market Segments) in which we believed competition was viable for the contestable part of the connection. We have used this market segmentation in developing our framework for RIIO-ED1.

1.4. For clarification, where in this document we describe 'minor' connections customers we are referring to connections undertaken in the Excluded Market Segments (these are segments where we do not consider competition is currently viable). 'Major' connection customers relates to connections undertaken in the Relevant Market Segments.

Table A2.1: Excluded and Relevant Market Segments

<table>
<tr><th colspan="2">Excluded Market Segments (metered and demand only) – minor connections</th></tr>
<tr><td colspan="2">Low Voltage (LV) connection activities relating to no more than four domestic premises or one-off industrial and commercial work (ie one to four houses)</td></tr>
<tr><td colspan="2">Connection activities in respect of a connection involving three-phase whole current metering at premises other than Domestic Premises. (ie one-off LV connections)</td></tr>
<tr><th colspan="2">Relevant Market Segments – major connections</th></tr>
<tr><td rowspan="4">Metered Demand Connections</td><td>LV Work: LV connection activities involving only LV work, other than in respect of the Excluded Market Segments.</td></tr>
<tr><td>High Voltage (HV) Work: LV or HV connection activities involving HV work (including where that work is required in respect of connection activities within an Excluded Market Segment).</td></tr>
<tr><td>HV and Extra High Voltage (EHV) Work: LV or HV connection activities involving EHV work.</td></tr>
<tr><td>EHV work and above: EHV and 132kV connection activities.</td></tr>
<tr><td rowspan="2">Metered DG</td><td>LV work: LV connection activities involving only LV work.</td></tr>
<tr><td>HV and EHV work: any connection activities involving work at HV or above.</td></tr>
<tr><td rowspan="3">Unmetered Connections</td><td>Local Authority (LA) work: new connection activities in respect of LA premises.</td></tr>
<tr><td>Private Finance Initiative (PFI) Work: new connection activities under PFIs.</td></tr>
<tr><td>Other work: all other non-LA and non-PFI unmetered connections work</td></tr>
</table>

1.5. To allow headroom for competition to develop we allow DNOs to earn a regulated margin (set at four per cent above cost) on contestable connection services in the Relevant Market Segments.

1.6. As part of DPCR5 DNOs are required to demonstrate whether effective competition exists in each of the Relevant Market Segments. This process is called the Competition Test. If we agree that effective competition has been established (ie the DNO passes the Competition Test) then we will lift margin regulation on contestable connection services in that segment. This process is ongoing until December 2013. We will review any of the Relevant Market Segments that have not passed the Competition Test in 2014 and may consider referral to the Competition Commission under competition legislation.

Impact of the Competition Test on RIIO-ED1 arrangements

1.7. We have been mindful of the impact of the Competition Test on our RIIO-ED1 arrangements and we set out below how the RIIO-ED1 regulatory framework will apply to different segments of the connections market following the DPCR5 Competition Test (Table A2.2).

Table A2.2: Impact of the Competition Test on the RIIO-ED1 arrangements

Incentive/Measure		Excluded Market Segments	Relevant Market Segments that pass the Competition Test		Relevant Market Segments that don't pass the Competition Test
			Contestable	Non-contestable	
GSOP		Apply	Apply	Apply	Apply
Time to Connect incentive		Apply	Not Apply	Not Apply	Not Apply
BMCS	Customer satisfaction survey	Apply	Not Apply	Not Apply	Not Apply
	Complaints metric	Apply	Apply	Apply	Apply
	Stakeholder engagement incentive	Apply	Apply	Apply	Apply
ICE		Not Apply	Not Apply	Apply	Apply

Incentives that will apply to all market segments

1.8. As noted in Chapter 8, the connections GSOP protects all connections customers from receiving unacceptably poor levels of service. Since the DNOs remain the connection provider of last resort for all customers, we have therefore decided that the connections GSOP will continue to apply to all market segments during RIIO-ED1.

1.9. We will not specify which stakeholders should, or should not, be captured as part of the DNOs' stakeholder engagement incentive submission during RIIO-ED1. The DNOs' submission may therefore capture engagement with all connections customers. However engagement with customers in Relevant Market Segments that have passed the Competition Test, and in particular where this has been used to gain a commercial advantage, will be taken into account during the assessment process and in our decision to allocate a financial reward.

1.10. The complaints metric incentivises DNOs to respond to complaints efficiently and effectively. We accept that, in principle, a DNO's handling of complaints from customers relating to contestable services in Relevant Market Segments, where there is effective competition, should not be subject to regulatory incentives. However we consider that in many instances it may be difficult to assess whether the complaint relates mainly to the contestable or non-contestable part of the DNO's connections service. We also note that the majority of complaints that are included in the BMCS complaints metric relate to supply interruptions (not connections) and that at least some major connections customers may choose to raise concerns over service outside of the formal complaint process. We therefore consider it acceptable and pragmatic that the complaints metric captures complaints from all connection market segments

Incentives that will only apply to Excluded Market Segments

1.11. In the absence of effective competition in the provision of connection services, we consider that regulatory arrangements are required to protect the customers' interests. To incentivise DNOs to produce high-quality, timely connections the Time to Connect incentive and customer satisfaction survey incentives will apply to connections work in the Excluded Market Segments.

Incentives that will only apply to Relevant Market Segments that do not pass the Competition Test

1.12. For connections work in markets where effective competition has not been demonstrated (ie Relevant Market Segments that have not passed the Competition Test), we consider that additional measures are necessary to ensure customer interests are protected. We consider that the customer satisfaction survey and Time to Connect incentives may not deliver improvements in the most critical areas for these connection customers. Instead, we have decided to introduce ICE to incentivise DNOs to engage and respond to the needs of these connection customers.

1.13. The ICE will operate on a penalty only basis to ensure that there is no incentive on the DNOs to not pass the Competition Test. The maximum penalty (0.9 per cent of base revenue) will be scaled to reflect the outcome of the Competition Test (eg the number of market segments that have passed the Competition Test or the size of the market segments that have passed the Competition Test). We will consult upon the approach used to scale the penalty prior to the start of RIIO-ED1.

Relevant Market Segments that pass the Competition Test

1.14. We consider that the presence of effective competition will protect customers from receiving poor levels of service for the contestable part of their connections work. We are therefore not proposing to apply incentives to the contestable part of the connections service, ie for Relevant Market Segments that pass the Competition Test.

1.15. We note that the DNOs are still responsible for completing non-contestable connection activities in these market segments. We consider that existing licence arrangements ensure that DNOs deliver specified standards of performance for these customers (eg Standard Licence Condition 15). To ensure that DNOs are incentivised to deliver best practice in the provision of non-contestable activities, we have decided that for the non-contestable activities the ICE will operate on a reputational basis in Relevant Market Segments that pass the Competition Test.

Appendix 3 – Connection Guaranteed Standards of Performance payment levels

The connections GSOP payments for DPCR5 and the proposed payment level for RIIO-ED1 (as described in Chapter 8) are set out in Table A3.1 below.[55]

Table A3.1: Proposed RIIO- ED1 connections GSOP payments

Reporting code	Service	RIIO-ED1	DPCR5
1A	Provision of budget estimate <1MVA	£65 - One off payment	£50 – One off payment
1B	Provision of budget estimate >1MVA	£65 - One off payment	£50 – One off payment
2A	Provision of a quotation for a single LV single phase service connection	£15 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched	£10 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched
2B	Provision of a quotation for small LV projects: ▪ 2-4 LV single phase domestic services or ▪ for connections to 1-4 LV single phase domestic premises involving an extension to the LV network or ▪ a single two or three phase whole current metered connection (not requiring an extension to LV network)	£15 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched	£10 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched
3A	Provision of any other LV demand quotation	£65 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched	£50 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched

[55] These figures have been derived using actual inflation data from the Office of National Statistics (for 2010-11 and 2011-12, RPI CHAW – financial year average), forecast data from the HM Treasury consensus forecast published August 2012 (for 2012-13 to 2015-16), forecast data from the Office of Budget Responsibility published in March 2012 (for 2016-17) and a long term RPI forecast of 2.5 per cent (2017-18 to 2018-19). The uplift applied to the DPCR5 payment levels reflects the cumulative inflation figure to the end of 2018-19.

Reporting code	Service	RIIO-ED1	DPCR5
3B	Provision of an HV demand quotation	£135 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched	£100 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched
3C	Provision of a EHV demand quotation	£200 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched	£150 for each working day after the end of the prescribed period up to and including the day on which the quotation is dispatched
4A	Contact customer (post acceptance) about scheduling <5 LV service connections covered by 2A & 2B	£15 for each working day after the end of the prescribed period up to and including the day on which contact occurs	£10 for each working day after the end of the prescribed period up to and including the day on which contact occurs
4B	Contact customer (post acceptance) about scheduling other LV demand connections	£65 for each working day after the end of the prescribed period up to and including the day on which contact occurs	£50 for each working day after the end of the prescribed period up to and including the day on which contact occurs
4C	Contact customer (post acceptance) about scheduling HV demand connections	£135 for each working day after the end of the prescribed period up to and including the day on which contact occurs	£100 for each working day after the end of the prescribed period up to and including the day on which contact occurs
4D	Contact customer (post acceptance) about scheduling EHV demand connections	£200 for each working day after the end of the prescribed period up to and including the day on which contact occurs	£150 for each working day after the end of the prescribed period up to and including the day on which contact occurs
5	Commence LV,HV & EHV demand works on customer’s site	£25 for each working day after the agreed date up to and including the day on which the works are commenced	£20 for each working day after the agreed date up to and including the day on which the works are commenced
6A	Complete service connection works	£35 for each working day after the agreed date up to and including the day on which the works are completed	£25 for each working day after the agreed date up to and including the day on which the works are completed

Reporting code	Service	RIIO-ED1	DPCR5
6B	Complete LV works (including phased works)	£135 for each working day after the agreed date up to and including the day on which the works are completed	£100 for each working day after the agreed date up to and including the day on which the works are completed
6C	Complete HV works (including phased works)	£200 for each working day after the agreed date up to and including the day on which the works are completed	£150 for each working day after the agreed date up to and including the day on which the works are completed
6D	Complete EHV works (including phased works)	£270 for each working day after the agreed date up to and including the day on which the works are completed	£200 for each working day after the agreed date up to and including the day on which the works are completed
7A	Complete LV energisation works (including phased works)	£135 for each working day after the agreed date up to and including the day on which energisation occurs	£100 for each working day after the agreed date up to and including the day on which energisation occurs
7B	Complete HV energisation works (including phased works)	£200 for each working day after the agreed date up to and including the day on which energisation occurs	£150 for each working day after the agreed date up to and including the day on which energisation occurs
7C	Complete EHV energisation works (including phased works)	£270 for each working day after the agreed date up to and including the day on which energisation occurs	£200 for each working day after the agreed date up to and including the day on which energisation occurs
8A	Emergency Fault Repair response	£65 one off payment	£50 one off payment
8B	High Priority Fault Repair – Traffic Light Controlled	£15 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed	£10 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed
8C	High Priority Fault Repair – non Traffic Light Controlled	£15 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed	£10 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed

Reporting code	Service	RIIO-ED1	DPCR5
8D	Multiple unit fault repair	£15 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed	£10 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed
8E	Single unit fault repair	£15 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed	£10 for each working day after the end of the prescribed period up to and including the day on which the fault rectification works are completed
9	Provision of a quotation – New Works order (1-100 units)	£15 for each working day after the end of the prescribed period up to and including the day the quotation is dispatched	£10 for each working day after the end of the prescribed period up to and including the day the quotation is dispatched
10A	New works order - completion of works on a new site	£15 for each working day after the end of the prescribed period up to and including the day the works are completed	£10 for each working day after the end of the prescribed period up to and including the day the works are completed
10B	New works order - completion of works on adopted highways	£15 for each day after the end of the prescribed period up to and including the day on which the works are completed	£10 for each day after the end of the prescribed period up to and including the day on which the works are completed
11A	Quotation accuracy review scheme challenge single LV single phase service connection (aligns to 2A)	£335 - one off payment	£250 – one off payment
11B	Quotation accuracy review scheme challenge for small LV projects (aligns to 2B)	£670 – one off payment	£500 – one off payment
12	Where a Distributor fails to make a payment under the regulations	£65 – one off payment	£50 – one off payment